URGENT MODIFICATION REPORT for Modification Proposal P135

Marginal System Buy Price During Periods of Demand Reduction

Prepared by: Pricing Issue Standing Modification Group

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This document has been distributed in accordance with Section F2.1.10[1] of the Balancing and Settlement Code.

RECOMMENDATIONS

On the basis of the analysis, consultation and assessment undertaken in respect of this Urgent Modification Proposal during the Modification Procedure, and the resultant findings of this report, the Panel recommends to the Authority that:

- **Proposed Modification P135 should not be made;**
- **If the Authority determine that the Proposed Modification should be made, the P135 Implementation Date should be 45 Business Days following an Authority determination that Proposed Modification P135 should be made.**

[1] The current version of the Balancing and Settlement Code (the 'Code') can be found at www.elexon.co.uk/ta/bscrel_docs/bsc_code.html

I CONTENTS TABLE

II DOCUMENT CONTROL

a Authorities

Version	Date	Author	Signature	Change Reference
0.1	15/08/03	Mandi Francis		
0.2	18/08/03	Mandi Francis		
0.3	19/08/03	Change Delivery		
0.4	22/08/03	Change Delivery		
0.5	04/09/03	Mandi Francis		
0.6	05/09/03	Change Delivery		
1.0	12/09/03	Change Delivery		

b Distribution

Name	Organisation
Each BSC Party	Various
Each BSC Agent	Various
The Gas and Electricity Markets Authority	Ofgem
Each BSC Panel Member	Various
Energywatch	Energywatch
Core Industry Document Owners	Various

c Related Documents

Reference	Document
Reference 1	Modification Proposal P135 ‘Marginal System Buy Price During Periods of Demand Reduction’ (National Grid Transco, 1 August 2003)

SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as BSCCo has been able to assess the following parties/documents have been initially identified as being potentially impacted by Urgent Modification Proposal P135.

Parties	
Suppliers	☒
Generators	☒
Licence Exemptable Generators	☒
Transmission Company	☒
Interconnector	☐
LDSOs[2]	☐
Party Agents	
Data Aggregators	☐
Data Collectors	☐
Meter Operator Agents	☐
ECVNA	☐
MVRNA	☐
BSC Agents	
SAA	☒
FAA	☐
BMRA	☒
ECVAA	☐
CDCA	☐
TAA	☐
CRA	☐
Teleswitch Agent	☐
SVAA	☐
BSC Auditor	☒
Profile Administrator	☐
Certification Agent	☐
MIDP	☐
TFLA	☐
Other Agents	
SMRA	☐
Data Transmission Provider	☐

Sections of the BSC	
A	☐
B	☐
C	☐
D	☐
E	☐
F	☐
G	☐
H	☐
J	☐
K	☐
L	☐
M	☐
N	☐
O	☐
P	☐
Q	☐
R	☐
S	☐
T	☒
U	☐
V	☐
W	☐
X	☒

Code Subsidiary Documents	
BSC Procedures	☐
Codes of Practice	☐
BSC Service Descriptions	☒
Service Lines	☐
Data Catalogues	☐
Communication Requirements Documents	☐
Reporting Catalogue	☐
MIDS	☐
Core Industry Documents	
Grid Code	☐
Supplemental Agreements	☐
Ancillary Services Agreements	☐
Master Registration Agreement	☐
Data Transfer Services Agreement	☐
British Grid Systems Agreement	☐
Use of Interconnector Agreement	☐
Settlement Agreement for Scotland	☐
Distribution Codes	☐
Distribution Use of System Agreements	☐
Distribution Connection Agreements	☐
BSCCo	
Internal Working Procedures and Systems	☒
Other Documents	
Transmission Licence	☐

[2] Licensed Distribution System Operator

1 SUMMARY AND RECOMMENDATIONS

1.1 Recommendation

On the basis of the analysis, consultation and assessment undertaken in respect of this Modification Proposal, and the resultant findings of this report, the BSC Panel recommends that:

- **Proposed Modification P135 should not be made;**
- **If the Authority determine that the Proposed Modification should be made, the P135 Implementation Date should be 45 Business Days following an Authority determination that Proposed Modification P135 should be made; and**
- **The development and implementation costs associated with Proposed Modification P135, namely £120,000 BSC Central Service Agent costs, and 117.5 man days of ELEXON effort should be noted.**

1.2 Background: Process and Timetable

Modification Proposal P135 'Marginal System Buy Price During Periods of Demand Reduction' (P135, Reference 1) was raised by National Grid Transco on 1 August 2003. P135 seeks to amend the Energy Imbalance Price calculation such that the System Buy Price is derived from the most expensive Offer Acceptance remaining in the Net Imbalance Volume, but only during times where demand control has been instructed by the Transmission Company (in accordance with OC6.1.2(c), (d) and (e) of the Grid Code) where there is insufficient generation to meet demand (see section 4 for a more detailed description of the Modification Proposal).

The Proposer requested that this Modification Proposal be treated as Urgent on the grounds that P135 is seeking to address a defect in the current trading arrangements that could lead to issues regarding security of supply this winter. Implementation of P135 is required in time for the start of winter, as a means to prevent the disconnection / reduction of demand under demand control (as a consequence of insufficient generation).

The Panel agreed with the Transmission Company's recommendation that P135 be treated as urgent, and consequentially the Panel requested the Authority to grant Urgent status. The Authority granted urgency on 4 August 2003 and agreed that P135 should be progressed to the following timetable by the Pricing Issues Standing Modification Group (PSMG):

- Week commencing 4 August 2003: Modification Group Meeting (6 August 2003);
- Week commencing 11 August 2003: Modification Group Meeting (13 August 2003);
- Weeks commencing 18 & 25 August 2003: Industry consultation and ELEXON consideration of solution;
- Week commencing 1 September 2003: Modification Group Meeting (2 September 2003) and Panel Paper/Urgent Report drafted (5 September 2003);
- 11 September 2003: Panel Meeting - Consideration of Urgent Report;
- 12 September 2003: Urgent Report provided to Authority for decision.

The PSMG met on 6 August 2003 to commence the assessment of P135. The PSMG reviewed the Urgent timetable associated with the Modification Proposal and considered the issues / defects set out in the Modification Proposal. The PSMG reviewed the assessment criteria associated with P135, to be used in determining whether P135 better facilitates the Applicable BSC Objectives.

The PSMG met again on 13 August 2003 to continue the assessment of P135. The PSMG further considered the issues / defect set out in the Modification Proposal and continued their assessment as to whether P135 addresses these defects, specifically in relation to the assessment criteria. The PSMG also agreed the format of the consultation on P135, and the requirements of the technical solution for P135. The results of the PSMG deliberations are set out in the remainder of this report.

The PSMG agreed that the documentation for the consultation on P135 should take the form of the draft Urgent Modification Report (at v0.4), and this was issued for industry consultation (following PSMG review) on Tuesday 19 August 2003, with responses requested by 8:00 Monday 1 September 2003. It should be noted that the request for Transmission Company analysis was issued at the same time as the consultation.

The PSMG met on 2 September 2003 to consider the responses made in respect of the consultation on P135, consider the impact assessments and to finalise the assessment of P135, and to agree their recommendations in respect of P135.

The majority of the PSMG agreed that Proposed Modification P135 should not be made.

Furthermore, the majority of the PSMG agreed that there should be no Alternative Modification proposed. Although a number of options were proposed which could, in the opinion of the majority of the PSMG, have formed an Alternative Modification that was better than Proposed Modification P135 at facilitating the Applicable BSC Objectives, the majority of the PSMG agreed that these options were not better than the current baseline.

Therefore the PSMG, via correspondence, agreed that if the Authority determined that P135 should be made, the Implementation Date should be 45 Business Days following any Authority determination that Proposed Modification P135 should be made. The draft Urgent Modification Report was provided to the PSMG and was also agreed by correspondence.

The draft Urgent Modification Report was provided to the Panel for consideration at its meeting of 11 September 2003. The Panel considered the deliberations and recommendations of the PSMG and unanimously agreed with the recommendations of the PSMG. The Panel agreed to recommend that Proposed Modification P135 should not be made.

1.3 Rationale for Recommendations

1.3.1 Rationale for Recommendations in Respect of Proposed Modification P135

The PSMG agreed, by majority, that Proposed Modification P135 should not be made. The Panel were unanimous in supporting the recommendation of the PSMG, for the rationale provided by the group.

The detailed deliberations of the PSMG are set out in sections 2 and 5, but in summary, the majority of the PSMG believe that implementation of a marginal price only at times of demand control potentially has the following implications:

- A marginal price only at times of demand control provides weak to non existent price signals into the forwards curves, i.e. Parties view of the forwards and spot prices in the future, (as it is a short term event, with potentially a small probability of occurrence, hence the price signal may be lost), and thus Parties are unlikely to see a price signal that requires a reaction now, i.e. to get plant on and contracted for the winter;

- Furthermore a marginal price only at times of demand control provides pricing signals that come too late to react to in real time, and therefore has the effect of 'clobbering' Parties that are short, when they effectively can do nothing about it;
- The risk of exposure to the marginal System Buy Price (SBP) at times of demand control may have perverse incentives, where generators withhold generation, or run part loaded in order to reduce the risk of plant trip at this time thus mitigate the risk of consequential exposure to the SBP for the full extent of the lost load (plant trip is considered to be more likely at times of system stress). This has the opposite effect to the aim of P135, which seeks to incentivise more generation to be made available;
- An extreme marginal SBP may mean that Parties that are short are exposed to Imbalance charges that exceed their Credit Cover, and in extreme cases cause bankruptcy of the Party in question. Where the settlement liabilities exceed the Credit Cover lodged, this places consequential risk on other Parties who will incur the cost of the Party failure;
- It poses the risk of an extreme System Buy Price; as the system is under stress, and the Transmission Company will have taken all feasible Offer Acceptances (at potentially high prices) before demand control is invoked. The majority of the PSMG believe that an SBP of in the region of £10,000 could be feasible;
- Suppliers may be perversely incentivised, as demand control may, depending on which GSP Group(s) are instructed, reduce their demand (all be it unpredictably), and have the effect of affecting the imbalance position of a Supplier such that a short Supplier becomes less short, and potentially long, and a long Supplier becomes longer. This may mean that those causing the demand control are not targeted to the full extent, thus reducing the incentive properties of P135;
- The potential for an extreme SBP places unmanageable risk on Parties; as demand control is expected to occur post Gate Closure, where Parties cannot react by trading, and therefore may be exposed to the marginal SBP with no way of mitigating the exposure; and
- Furthermore, where a Party becomes short, for example following a plant trip, and tries to trade out the potential imbalance by contracting for subsequent Settlement Periods, i.e. becoming a distressed buyer, it is unlikely that other Parties will take the risk of trading with them, given the distressed buyers potential credit position, as the other Parties will not be sure whether the distressed buyer is in a position to meet the contract price, as the exposure to the marginal SBP could have been catastrophic.

A minority of the PSMG, including the Proposer, believe that Proposed Modification P135 does provide more appropriate incentives on participants to contract forward and ensure they have an adequate level of contract cover for the winter. These PSMG members believe that P135 achieves this by ensuring that imbalance prices better reflect the underlying opportunity cost of providing marginal balancing energy. By ensuring participants face the underlying cost of procuring marginal balancing energy, the correct balancing incentive is achieved which allows efficient forward contracting decisions to be made. It was asserted that a marginal imbalance price, rather than average imbalance price, provides a more appropriate price signal and associated incentives.

These PSMG members believe that incentivising forward contracting will assist participants in being able to achieve a balanced position and reduces the likelihood of Demand Control being required, improving security of supply. By contracting sufficiently and reducing the likelihood of Demand Control being necessary, the risks identified above are less likely to occur.

1.3.2 Rationale for not recommending an Alternative to P135

The majority of the PSMG did not support taking forward any of the options that were proposed as potential alternatives to P135 (set out and discussed in Annex 6).

Of those PSMG members that do not support Proposed Modification P135, after careful consideration of the issues and the options, the majority believe that P135 should be rejected, for the reasons set out in section 1.3.1, and that any Alternative Modification, whilst it may improve on P135, is not better than the current baseline, merely 'less bad' than P135. It was noted that those parties that had offered an option as an alternative to P135 considered the option only to be better than P135, not the baseline, and had offered the alternative option with the intent of attempting to mitigate the perceived negative aspects of Proposed Modification P135, should it be approved by the Authority.

A minority of those PSMG members that do not support P135, believe that an Alternative should be proposed for P135, in order that a better option is provided to the Panel and the Authority for determination. However, each of these PSMG members had a different preferred Alternative (set out in Annex 6), noting that none of those that proposed an Alternative believed it to be better than the current baseline, only better than P135.

The majority view was that there would be no Alternative Modification proposed for P135, because whilst, in the opinion of some of the PSMG, these potential alternatives reduced some of the adverse effects of P135, they did not solve the fundamental problems and not all were seen as addressing the stated defects of P135.

1.3.3 Requirement for Prompt Pricing for Proposed Modification P135

The PSMG considered the solution for P135, and the impact assessments provided in respect of it.

It was noted that the identified manual solution cannot deliver an Indicative System Buy Price (i.e. the marginal SBP) until Settlement Day plus two Business Days (D+2). The majority of the PSMG considered this to be unacceptable for two reasons:

- Where a Party becomes short, for example following a plant trip, and tries to trade out the potential imbalance by contracting for subsequent Settlement Periods, i.e. becoming a distressed buyer, it is unlikely that other Parties will take the risk of trading with them, given the distressed buyers potential credit position, as the other Parties will not be sure whether the distressed buyer is in a position to meet the contract price, as the exposure to the marginal SBP could have been catastrophic. If the marginal SBP is known and it can be seen that it is not extreme, Parties may react differently and trade with the distressed buyer, thus ameliorating their position. Where Parties cannot see the price, it is considered that they will not take the risk of trading, and the distressed Parties position is exacerbated, with potentially catastrophic consequences; and
- Parties will want to know their liabilities as soon as possible following a Settlement Period where demand control was called, in order to take any action required to mitigate exposure to imbalance, or to set in train other activities, such as amendments to credit cover, etc.

A minority of the PSMG believe that, although prompt pricing is desirable, it is not essential, as there is potential for the price to change materially away from that reported in real time, making the real time price unreliable.

A marginal price, derived from the last balancing action remaining in the Net Imbalance Volume (NIV) will be dependent on the volume in the Bid and Offer stack, and may change where these volumes change. For example, BSAD is not finalised until a number of days after real time (D+2WD), where there is the potential for the volume of Balancing Services Adjustment Data (BSAD) to change (sales and / or purchase). Any volume change will affect the NIV derivation, and thus the balancing action used to set the Energy Imbalance Price. If the balancing action changes, the price of the action may change, and this change may be material, depending on the price of the next balancing action in the stack.

Furthermore, changes, such as manifest errors etc. may change the price associated with an Offer Acceptance causing a re-ordering of the stack, and a consequential change to the balancing action that sets the price. Changes to Transmission Loss Multipliers (TLMs – as metered volumes change between Settlement Runs) may also impact the balancing action that is used to set the marginal price.

Therefore there is far more scope for changes to a marginal Energy Imbalance Price, than a weighted average.

Furthermore, the intent of P135 is to send price signals ahead of real time in order to incentivise action ahead of the Settlement Period, and therefore it could be argued that a prompt price is irrelevant to this intent and that the absence of a prompt price in no way invalidates P135.

However, the majority of the PSMG consider prompt pricing to be essential for P135, even considering the potential for inaccuracies in the price reported.

ELEXON are currently exploring a semi-automated workaround whereby the marginal Indicative System Buy Price is calculated and published on the Balancing Mechanism Reporting Agent (BMRA) in real time for all Settlement Periods (section 1.3.5).

1.3.4 P135 Proposed Modification: Implementation Approach

ELEXON has reviewed the requirements of the PSMG and the impact assessments provided in respect of P135 (section 1.3.5), and propose that the semi-automated solution be implemented, for the rationale set out below, noting the PSMG requirement for prompt price reporting, as the majority of the group believe it to be essential to P135 (section 1.3.3).

ELEXON recognise the urgency of implementing P135, and thus explored the option of implementing a manual solution immediately, followed by the automated solution. However, given the nature of the amendments required, it was determined that the two solutions could not be developed in parallel, i.e. it would not be possible to implement P135 with a manual solution in 35 Business Days, followed by the semi-automated solution 10 Business Days after that (running the development of the two solutions in conjunction).

In effect, implementing the manual solution followed by the automated solution would result in an implementation lead time of 35 days for the manual solution, and then an additional 45 Business Days for the semi-automated solution.

Whilst this option was considered, it was also noted that:

- The full costs of both implement options would be incurred, i.e. there would be very little amelioration of BSC Central Service Agent costs and ELEXON resource for implementing both options, as both are effectively standalone amendments, being done outside of a BSC Systems Release; and
- There would be no prompt price reporting available until the automated solution was implemented, effectively 45 Business Days following the implementation of the manual solution.

ELEXON propose that only the semi- automated solution is implemented, for the following reasons:

- Prompt price reporting would be available immediately on implementation, as requested by the PSMG;
- The development and implementation costs of the manual solution are similar to those for the semi-automated solution (noting that the manual solution carries a material operational cost, whereas the semi-automated solution carries a relatively small operational cost); and
- The additional timescale for implementing the semi-automated solution is only 10 Business Days (2 weeks) over that for the manual solution.

Therefore the Implementation Date and the quoted costs and timescales reflect this approach.

1.3.5 Proposed Modification P135 Costs and Timescales

There are two potential options for delivery of the solution set out in section 1.3.4 in time for winter 2003 / 2004; a manual solution and a semi-automated solution.

It should be noted that if it is considered to be appropriate, an enduring systems change will replace either of these solutions in time for the Final Reconciliation Settlement Run (in order to ensure the accuracy of the 'last' Energy Imbalance Prices used in the Settlement Calculations). It should be noted that the implementation of an enduring system solution is not guaranteed, as it will depend upon the accuracy of either of the workarounds, and the number of Settlement Periods falling in demand control periods over the coming winter (for example, if there are very few, then the cost and effort of developing an enduring systems solution may be deemed to be unnecessary).

1.3.5.1 P135: Proposed Modification Semi-Automated Solution

The system solution does not equate to a solution in the BSC Central Service Agent impact assessment, and at a high level (a more detailed technical solution is provided in section 4.2.3), it requires that:

1. BMRA publishes notification of the start and end of the demand control in the form of a System Warning Message, as notified by the Transmission Company;
2. For every Settlement Period BMRA will, in the same timescales as the Indicative Energy Imbalance Price calculation (i.e. 45 minutes following the end of the Settlement Period), derive and calculate the Indicative (marginal) System Buy Price, i.e. the SBP had the Settlement Period fallen within a Demand Control Period, and publish this on the System Warnings and Other Messages screen, **i.e. prompt price reporting**. BMRA will also publish the *increase* in the NIV required to move to the next marginal SBP, and that price, and the *decrease* in NIV required to move to the next marginal SBP and that price (i.e. what the Offer prices either side of the marginal Offer Acceptance in the NIV are);
3. The Transmission Company will notify BSCCo of the Demand Control Period in complete Settlement Periods, and BSCCo will publish this on the BSC Website. BSCCo will also notify the SAA of the Demand Control Period (in Settlement Periods); and
4. For all Settlement Periods falling within a Demand Control Period, SAA will derive a marginal SBP when calculating the System Buy Price. There will be no amendment to the Settlement Reports.

In terms of the effort required for the semi-automated solution:

BSC Central Service Agent Costs:

INDICATIVE £43,511 change specific + **operational: £6,091 p.a**. (maintenance) and **£168 per incident**;

INDICATIVE £76,141 release cost (as outside of a formal release); and

Lead time of **45 Business Days**.

ELEXON Development and Implementation Effort:

Total ELEXON development and Implementation Effort: **115 man days** plus an unspecified amount of BSC Auditor effort.

Lead time **30 Business days.**

1.3.5.2 P135: Proposed Modification Manual Solution

The manual solution equates to manual solution 1a in the BSC Central Service Agent impact assessment, and at a high level, it requires that:

1. BMRA publishes notification of the start and end of the demand control in the form of a System Warning Message, as notified by the Transmission Company;
2. The Transmission Company will notify BSCCo of the Demand Control Period in complete Settlement Periods, and BSCCo will publish this on the BSC Website;
3. For each Settlement Period that falls during a Demand Control Period, BSCCo will calculate the marginal System Buy Price, using TOMAS, and will publish this at D+2 Business Days on the BSC Website, **i.e. there will be no prompt price reporting**;

For each Settlement Run from Interim Information to Final Reconciliation:

4. BSCCo will calculate the marginal SBP for each Settlement Period that falls during a Demand Control Period, using the latest available data (usually the output from the last Settlement Run);
5. BSCCo will notify the SAA of the required SBP for each affected Settlement Period;
6. SAA will then run an ad hoc Settlement Run, withholding reports, to determine the value that the BPA needs to be set to in order to derive the correct SBP;
7. SAA will amend the BPA to the required value and run settlement to the settlement timetable, so all reports are generated to Parties. There will be no amendment to the Settlement Reports.

In terms of the effort required for the manual solution:

BSC Central Service Agent Costs:

£22,890 change specific + **operational: £25,296 p.a**. and **£20,051 per incident**; and

Lead time of **35 Business Days**.

ELEXON Development and Implementation Effort:

Total ELEXON development and Implementation Effort: **147.5 man days** plus an unspecified amount of BSC Auditor effort.

Lead time **30 Business days**.

It should be noted that the ELEXON effort is required mainly as a consequence of the requirement for TOMAS (the system that would be used under this mechanism to derive the System Buy Price) to operationally calculate the Energy Imbalance Price. Consequentially, the level of testing, CVA Programme support and BSC Auditor effort are increased over a 'normal' TOMAS change, in order to ensure that TOMAS is sufficiently robust to derive operational Energy Imbalance Prices (i.e. a level over and above that required to monitor the market).

2 SUMMARY OF P135 ASSESSMENT ISSUES

The following is a summary of the deliberations / considerations of the PSMG in respect of the issues agreed by the PSMG as the key issues for consideration in the assessment of P135. The deliberations are set out in full in Section 5 of this report. Other issues were raised by the consultation responses, and the PSMG deliberations in respect of these issues are provided in section 8, however, the PSMG believe the issues set out below to be the key considerations in respect of P135.

It should be noted that the PSMG have not reached any quantitative conclusion on the effects of P135 in respect of these issues, as the effects are behaviour based, and thus cannot be quantitatively assessed.

However, a large majority PSMG have made a qualitative assessment of their perception of the effect of P135 on behaviour of Parties and in relation to the arguments set out against these issues, and have concluded that the detrimental effects of P135 (as set out in the counterarguments – the 'NOs' below) outweigh any benefit, and thus have determined that P135 does not better facilitate the Applicable BSC Objectives than the current baseline, and therefore P135 should not be made.

A minority of the PSMG (including the Proposer) believe that P135 will better facilitate the Applicable BSC Objectives than the current baseline for the reasons set out in the arguments for P135 (the 'YESs' below).

2.1.1 Marginal Price Assumptions

The PSMG noted that no accurate assessment of the likely System Buy Price during demand control periods can be undertaken, as it is impossible to determine behaviour at times of system stress, and the price will depend on many factors that cannot be assessed in advance. However, the PSMG did feel that there is a likelihood that a marginal SBP would be an order of magnitude higher than that of the current SBP.

2.1.2 Incentives to Balance

Does P135 incentivise Parties to further balance their position ahead of Gate Closure?

YES:

- Marginal System Buy Price during times of demand control sends a stronger signal to Parties to be able to balance, in particular not go short and be exposed to SBP;

- Even where a Supplier is directly affected by the reduction of their metered demand under demand control (say in one GSP Group), their overall 'pre-demand control' imbalance position is unlikely to be changed significantly by demand control, as it is not applied nationally. Therefore a Supplier's imbalance position is unlikely (except in marginal cases) to be 'flipped' from short to long by the application of demand control; and

- Furthermore, a Supplier is unlikely to be aware in advance as to where and how demand control will be applied and thus is unlikely to take the risk of deliberately going short in the expectation that their (short) imbalance position is ameliorated by the demand control.

NO:

- Marginal System Buy Price during times of demand control could incentivise (most) types of Generator to withhold generation from the market in case of trip;

- Marginal System Buy Price only during times of demand control means that the signal of system stress, and the associated incentive to balance comes, in the long term too late for getting plant into service for the winter, and in the shorter term, too late to enable parties to react by contracting ahead of Gate Closure;

- Demand control that does not have a volume reflected in the Net Imbalance Volume may be outweighed by Bids taken to match generation to demand following demand reduction. This may send the market long, weakening the price signal / creating perverse incentives, as the System Sell Price becomes the main Energy Imbalance Price;

- Demand control that is not reflected in Suppliers' imbalance positions may have the effect of sending short Suppliers long, and long Suppliers longer, thus exposing them to System Sell Price and so reducing the incentives on Suppliers to balance ahead of Gate Closure; and

- A marginal imbalance price only in one direction will incentivise length, not balance. Even with an average price, the risk averse strategy is to go long to avoid exposure to System Buy Price, a marginal SBP may just have the effect of increasing that length.

2.1.3 Security of Supply

Does P135 improve security of supply? (noting that this issue is heavily related to the issue in respect of incentives to balance).

YES:

- Marginal System Buy Price during times of demand control sends a stronger signal to Parties to ensure that they are able to balance and avoid exposure to SBP. This promotes trading in the forwards markets which will ensure that there is sufficient generation available to meet demand, avoiding the requirement for demand control;

NO:

- The current trading arrangements are adequate in respect of security of supply, i.e. the status quo should be retained;

- Marginal System Buy Price during times of demand control will incentivise Generators to withhold generation from the market in case of trip. This could have the effect of exacerbating the requirement for demand control; and

- Assuming withheld plant, a marginal System Buy Price could incentivise Generators that trip in a period near to / during demand control to breach the Grid Code by bringing on withheld plant to meet their contracted position in order not to be short. This may increase operational issues for NGC.

2.1.4 Other Incentives from P135

Are there any other incentives on Parties that P135 may introduce, and are these beneficial or detrimental, and is there a trade off in any direction?

The PSMG did not believe there to be any further incentives from P135 that have not already been explored.

2.1.5 P135 and the Likelihood of Demand Control

Will the implementation of P135 decrease the likelihood of demand control?

The PSMG noted that the perception of whether P135 is likely to decrease the likelihood of demand control depends on the perception as to whether the pricing signals are strong and timely enough to influence the long term behaviour of Parties (section 5.1.2).

In summary:

- Yes; if Parties respond to P135 by forward contracting and incentivising the availability of more generation; and
- No; if Parties respond to P135 by withholding generation to self insure against the risk of exposure to a marginal System Buy Price if they trip during a demand control period.

2.1.6 P135 as the 'Correct' Mechanism

Is P135 the correct mechanism for dealing with the problem of potential generation shortage this (and coming) winter? Is there a different way of ensuring that generation matches demand?

A number of the PSMG believe that Parties should forward contract in sufficient volumes to cover themselves at times of peak demand (implying more generation comes on in response), and that price signals are the way to achieve the incentive to contract.

In summary – yes, if it is believed that P135 will send sufficiently strong price signals, in a sufficiently timely manner.

No, if it is believed that:

- There are other ways to ensure that generation meets demand, for example by the Transmission Company contracting outside of the Balancing Mechanism for the required generation;
- The price signals from P135 will be too weak and too late to respond by forward contracting;
- The incentives on Parties are such that they will not respond to P135 by forward contracting (for example the perception of risk).

2.1.7 Marginal vs Average Pricing

All Parties in imbalance in the same direction as the system energy imbalance (Net Imbalance Volume) are contributing to the cost of the marginal energy balancing action (as it is not possible / appropriate to determine any energy apportionment), and therefore the Energy Imbalance Price applied should be marginal. Is this true? Or is average pricing more appropriate for the electricity market?

This issue, again, depends on the perception of what the Energy Imbalance Prices are seeking to achieve and whether average or marginal prices send the most appropriate signals to the market. These arguments are set out in previous sections.

2.1.8 Potential for Market Manipulation

Parties could perceive that a marginal pricing methodology would be open to gaming (as was the perception under the Pool), and thus an average methodology would mitigate gaming. Is the potential for gaming present under P135?

The PSMG noted that the perception of gaming under the Pool arose as a consequence of Generators being *paid* the marginal price for generating. Under the current trading arrangements, Parties are paid as bid in the balancing mechanism and pay the marginal SBP. Therefore the opportunity for gaming is reduced. The majority of the PSMG did not believe gaming to be an issue for P135.

2.1.9 Definition of a Marginal Price

Is the definition of a 'marginal' price in the Modification Proposal appropriate, or is a different definition (alternative Modification) more appropriate, and (if appropriate) does the benefit of getting P135 implemented for this winter outweigh any 'purist' arguments with respect to a marginal price?

The view of the PSMG is that the Modification Proposal is quite clear as to the marginal price, namely the most expensive Offer Acceptance (or part of) that remains in the Net Imbalance Volume. The PSMG believe that this is an appropriate mechanism for setting the marginal price for P135, given the limited circumstance of application.

2.1.10 Credit Cover Arrangements

Is Credit Cover under P135 any more of an issue than under the current arrangements?

The potential for Party default as a consequence of 'extreme' Energy Imbalance Prices exist currently. The majority of the PSMG agreed that their concerns regarding the potential for BSC Parties to be exposed to the consequences of a Party default, in conjunction with the potential for P135 to exacerbate the circumstances under which this may occur, should be highlighted in this report. No further consideration of the implications of P135 on the Credit Cover arrangements will be undertaken as part of P135.

2.1.11 Risk Management: Insurance Products

Will the implementation of P135 increase the availability of new / existing insurance products for covering the risk of exposure to an extreme System Buy Price?

A number of PSMG members noted that there is currently no insurance product available to hedge / address risk associated with events that occur after Gate Closure (only pre-Gate Closure). Therefore, since P135 implements a marginal SBP during periods of demand control, which occur post Gate Closure, a number of the PSMG believe that this may prevent the emergence of appropriate insurance products. Conversely, the implementation of P135 could create a market suitable to the emergence of such insurance products.

3 INTRODUCTION

This Report has been prepared by ELEXON Ltd., on behalf of the Balancing and Settlement Code Panel ('the Panel'), in accordance with the terms of the Balancing and Settlement Code ('BSC'). The BSC is the legal document containing the rules of the Balancing Mechanism and Imbalance Settlement process and related governance provisions. ELEXON is the company that performs the role and functions of the BSCCo, as defined in the BSC.

This Urgent Modification Report is addressed and furnished to the Gas and Electricity Markets Authority ('the Authority') and none of the facts, opinions or statements contained herein may be relied upon by any other person.

An electronic copy of this document can be found on the BSC website, at www.elexon.co.uk

4 DESCRIPTION OF PROPOSED MODIFICATION

4.1 Overview of P135

4.1.1 Mechanism for P135

P135 'Marginal System Buy Price During Periods of Demand Reduction' seeks to amend the Energy Imbalance Price calculation, only during periods of demand control and where the system is short, such that the most expensive energy balancing Offer Acceptance remaining in the Net Imbalance Volume (NIV) sets the System Buy Price.

Demand control events are defined in OC6 of the Grid Code, and it is the intent of P135 that demand control, for the purposes of P135, be limited to three demand control types, described below, and further limited to periods where demand control was instructed for non locational reasons, as a consequence of insufficient generation to meet demand:

- 'Demand Reduction instructed by NGC' (this is the most likely event);
- 'Automatic low frequency Demand Disconnection'; and
- 'Emergency manual Demand Disconnection'.

It should be noted that there are other types of demand reduction, for example, demand reduction instructed by the Secretary of State in accordance with the Electricity Supply Emergency Code. For the avoidance of doubt, P135 does not cover any other types of demand reduction / control than those defined above (namely OC6.1.2 (c), (d) and (e)).

The start and end of demand control will be notified by the Transmission Company (via a System Warning Message on the Balancing Mechanism Reporting Service (BMRS)) as close to real time as is practicable.

Post event, the Transmission Company will define the time period that demand control was active (by a start time and an end time) and notify this as a "Demand Control Period".

During the period of demand control and when the market is short (NIV>0), the System Buy Price for each settlement period that falls within, or partly within, a "Demand Control Period" will be calculated at the price of the most expensive accepted whole (or part) Offer Acceptance in the NIV for that Settlement Period.

The table below summarises which calculation will be affected by P135:

Imbalance Price	**NIV**	**Under normal system conditions**	During a "Demand Control Period"
SBP (Main Price)	**> 0**	Existing BSC methodology	Proposed 'Marginal' Methodology
SBP (Reverse Price)	**≤ 0**	Existing BSC methodology	Existing BSC methodology
SSP (Main Price)	**≤ 0**	Existing BSC methodology	Existing BSC methodology
SSP (Reverse Price)	**> 0**	Existing BSC methodology	Existing BSC methodology

P135 does not change any other aspects of the Energy Imbalance Price calculation, such as the mechanism for NIV Tagging, the derivation of the Energy Imbalance Prices outside of demand control periods and the derivation of the 'reverse' Energy Imbalance (i.e. the Energy Imbalance Price applied to Energy Imbalances in the opposite direction to the system) at times of demand control.

Figure 1 represents the price setting mechanism. The NIV Tagging mechanism derives the 'length' of the system by comparing the Accepted Offer (and BSAD purchase) volume with the Accepted Bid (and BSAD sales) volume. Where the Offer volume exceeds the Bid volume, then the NIV is positive, and the system is considered to have been short (insufficient generation to meet demand) in that Settlement Period.

The current mechanism calculates a volume weighted average price from the Accepted Offers (and Energy BSAD (Balancing Services Adjustment Data) if present) remaining in the NIV (i.e. the volume 'left' when the Accepted Bid volume is netted off the Accepted Offer volume). The NIV represents the volume associated with energy balancing the system. The system balancing actions are those that are netted off by NIV Tagging.

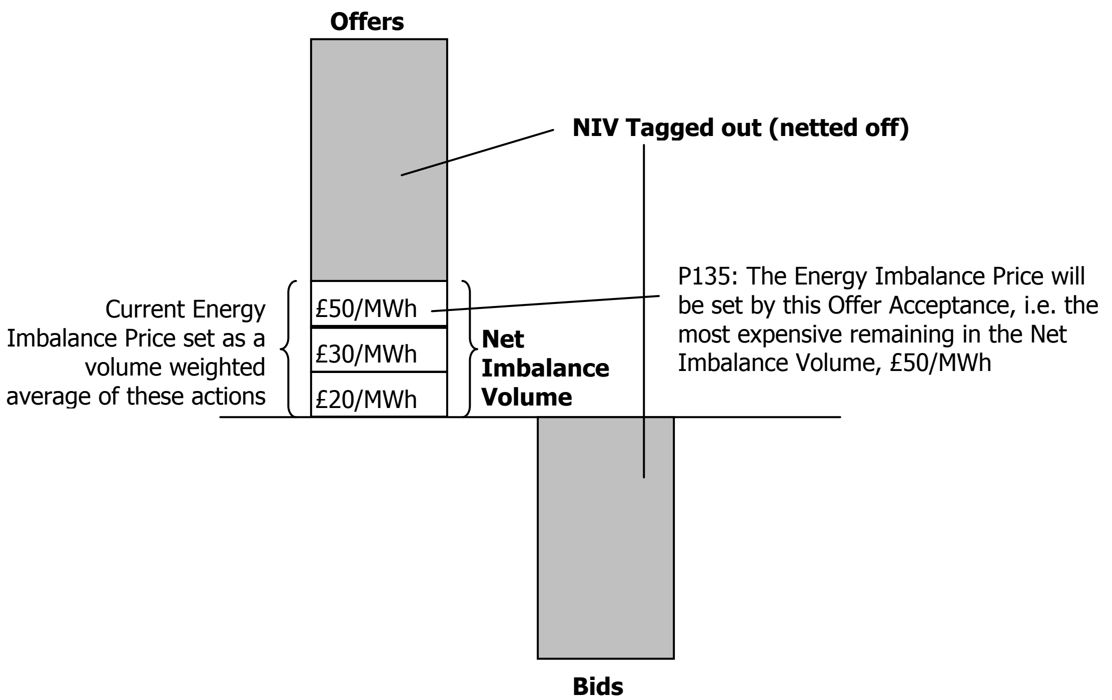

Figure 1: P135 Price setting mechanism during periods of demand control and where the Net Imbalance Volume is positive

4.1.2 Proposer's Rationale for Raising P135

In terms of the justification for P135, the Proposer, in the Modification Proposal, asserts that the experience of imbalance prices to date shows that the average imbalance price can significantly understate the cost of the marginal balancing action. This occurs particularly in times of energy shortage (i.e. high demand and/or low generation availability) when the marginal cost of balancing energy is likely to be high, and the differential between the average price and the marginal price is the greatest.

The Proposer believes that average imbalance prices send weakened price signals to the forward markets which may threaten security of supply this winter. Particularly in times of energy shortage, the averaging price methodology used to calculate imbalance prices means that market participants will not be exposed to the full cost of the marginal balancing action required to energy balance generation and demand. Thus there is insufficient incentive for Parties to contract in the forward markets to mitigate the risk of not being able to achieve a balanced position in all scenarios. During periods of energy shortage this could lead to involuntary customer demand control.

Furthermore, the Proposer asserts that "the calculation of the 'main' energy imbalance price, using a marginal methodology, will provide more appropriate price signals to incentivise Market Participants to contract forward in order to mitigate the risk of not being able to balance at Gate Closure. This is because marginal pricing provides an undiluted signal to the market as to the underlying cost of supplying the last increment of energy required to balance generation and demand. … It is particularly important that imbalance prices provide appropriate signals in times of energy shortage, as weakened signals could threaten security of supply."

The proposed change to the 'main' energy imbalance price calculation is limited to SBP during periods of demand control (as clarified above, demand control instructed in accordance with OC6.1.2(c) to (e) of the Grid Code) only, so that implementation could potentially be achieved as soon as possible. It is anticipated that the risk of exposure to a marginal imbalance price during these periods should improve incentives to market participants to contract sufficiently so as to reduce the risk of such demand control measures becoming necessary.

4.2 PSMG Discussion and Definition of P135

4.2.1 P135 and Demand Control

The Proposer presented P135 to the PSMG at its meeting of 6 August 2003. The Proposer asserts that they raised P135 because they believe that the signals provided to the forwards market from the current average Energy Imbalance Price are inappropriate, specifically during periods of energy shortage, as a consequence of the current average methodology understating the marginal price of energy.

Furthermore, the current indication is that plant margins are reducing, and this is likely to impact on the security of supply for this winter, unless pricing signals / incentives are improved.

P135 proposes a limited scope solution, namely to limit marginal pricing to the System Buy Price during periods where demand control was instructed for non locational reasons, due to there being insufficient generation to meet demand. The main reason for this is to ensure that there is a solution in place for this coming winter, i.e. by the end of October 2003.

Demand control is defined in OC6 of the Grid Code, and there are effectively five types of demand control covered by OC6 (defined in OC6.1.2):

(a) "Customer voltage reduction initiated by Network Operators (other than following NGC instruction);

(b) Customer Demand reduction by Disconnection initiated by Network Operators (other than following NGC instruction);

(c) Demand Reduction instructed by NGC;

(d) Automatic low frequency Demand Disconnection; and

(e) Emergency manual Demand Disconnection".

P135 does not cover (a) and (b) as they are Licensed Distribution System Operator initiated. (c), (d) and (e) are instructed by the Transmission Company and are therefore the only ones covered by P135.

The Proposer intended that P135 would be limited to periods where demand control was instructed for non locational reasons, due to there being insufficient generation to meet demand, and would not cover any other types of demand control / reduction and these are therefore out of scope of P135.

Demand Reduction instructed by the Transmission Company ((c) above) involves the Transmission Company instructing Licensed Distribution System Operators (LDSOs) to reduce demand by 5% (to a maximum of 40% of demand (OC6.5.4(b)). LDSOs can achieve demand reduction either by voltage reduction, or by customer disconnection. Low frequency demand disconnection ((d) above) occurs automatically, only where the system is close to failure, and emergency manual demand disconnection ((e) above) occurs where the Transmission Company opens the system breakers where the system has failed.

The Proposer believes that OC6.1.2(c) will be the most likely form of demand control instigated in relation to P135.

In terms of how the Transmission Company initiates demand control, where the Transmission Company believes demand control to be required, i.e. there is a shortage of generation to meet demand, the Transmission Company will identify the size of the generation shortfall, based on its near real time demand forecast, and estimate the volume of demand reduction required in order to maintain control of the Transmission System.

The Transmission Company will determine, for each Grid Supply Point (GSP) Group, the system flows and thus the demand for each GSP Group. The Transmission Company will then identify the GSP Group that will be most effective in resolving the mismatch between generation and demand. The Transmission Company then instructs the relevant LDSO to reduce demand in this GSP Group via an Emergency Instruction in accordance with the provisions laid down in OC6 of the Grid Code. Post event, the LDSO will inform the Transmission Company of the MW reduction achieved by demand control. Therefore it can be seen that demand control is not a despatchable 'firm service', but an emergency action of last resort, and that the delivery of demand control is in the hands of the LDSO.

4.2.2 PSMG Discussion and Definition of P135

As the scope of P135 deliberately excluded addressing the issue of how unsupplied demand is treated, the Proposer acknowledges that P135 has limitations. There was a perception amongst some members of the PSMG that, as the unsupplied demand was not treated in the Settlement process, a Supplier with a 'short' position (i.e. under contracted for its demand) will be sent long by the demand control, when metered volume will be removed from the Supplier's metered position by the demand control. However, the Proposer believes that P135 will still provide sufficient incentives, as, in respect of unsupplied demand:

(a) Unsupplied demand is not counted for; demand control could be reducing demand that has not appeared (i.e. been metered), and therefore demand control may not have the effect of reducing metered offtake, it may simply mean that metered offtake does not rise above that prior to demand control; and

(b) Demand control is most likely to be undertaken by one LDSO, on instruction from the Transmission Company, and thus is not national (uniform across all Suppliers). This change in demand is unlikely to represent a significant portion of the Supplier's demand, and may not have a significant effect on the Supplier's overall position and hence the incentive to balance remains.

It was noted that the Transmission Company wish to avoid demand control situations, and furthermore, would not instruct demand control for commercial reasons, only for operational reasons, as it is an Emergency Instruction. It was also noted that all other feasible and relevant balancing actions would be taken (including demand reduction offered as a commercial ancillary service by some BSC Parties / sites), in accordance with the Balancing Principles Statement and that a demand control Emergency Instruction was an instruction of last resort.

A number of PSMG members raised the concern that the volume reduction associated with demand control was not included in the Offer Acceptance 'stack' for inclusion in the NIV. Furthermore, they stated that if the volume of demand control is not taken into account in the derivation of the NIV, and thus the system length, then it could detrimentally impact the Energy Imbalance Prices (by understating the 'length' of the system).

The rationale supporting this belief is that, where demand control is exercised, all possible commercial and balancing actions have been taken, and specifically, all Offers have been exhausted. Thus where demand control is instructed, there may be an increase in the Bids taken in the Balancing Mechanism, in order to meet the new demand levels. Therefore, if demand control is not seen as a volume on the Offer stack for the NIV Tagging, then the NIV may end up negative (Bids > Offers) for the Settlement Period, with the System Sell Price as the main price (not System Buy Price).

Concerns were raised at the PSMG meeting, with regards to the further implications on the Energy Imbalance Price to be applied in the Settlement Period; if there are fewer Offer Acceptances as a result of the demand control, then provisions for the most applicable Offer Acceptance to be used as the Energy Imbalance Price may be needed. For example, a freeze on the Energy Imbalance Price, (e.g. the price associated with the last (energy) Offer Acceptance taken before demand control was instructed) for the duration of the demand control, to ensure that the correct pricing signals are getting through.

The Proposer confirmed that the issue of inclusion of demand control volumes in the NIV derivation had been considered during the development of P135, but had been excluded due to the need for urgent implementation. The Proposer noted that actual volumes associated with demand reduction would be difficult to derive (and more difficult to allocate to specific BM Units / BSC Parties), and furthermore the derivation of the associated price (for placing the 'action' into the stack) could be considered to be even more complex / problematical, although this would only be an issue where the action was for energy balancing. Thus making this aspect infeasible for inclusion in P135[3].

A question was raised as to whether the Transmission Company would instruct demand control for the purposes of creating margin / operational headroom. The Transmission Company responded that in a demand control situation, all reserve would have been used, but there is always a requirement to maintain an appropriate level of frequency response to maintain system security.

A question was raised as to why the Proposer has limited the implementation of the marginal System Buy Price to periods of actual demand control covered by P135, rather than to periods encompassing warnings of demand control where it could be argued that 'better' price signals providing a signal around the period of system stress, allowing Parties to react to that signal before demand control is instructed.

The Proposer stated that the limitation was to avoid the perception that the Transmission Company may declare a system warning in order to set a marginal price. A number of PSMG members noted that this feature may have some benefit, as Energy Imbalance Prices should be high at times of stress.

Furthermore, the Transmission Company noted that they were concerned with implementing P135 for this winter, and noted that system warnings would / could occur often. The Transmission Company therefore considered that the limitation of P135 to relevant periods of demand control, which would occur less frequently than system warnings, would enable a quicker implementation and not endanger implementation for this winter. Furthermore, the Transmission Company noted that marginal pricing during periods of demand control covered by P135 sends a warning signal to the market at times of system stress, such that Parties are more strongly incentivised to balance ahead of Gate Closure.

4.2.3 High level Solution for Proposed Modification P135

It should be noted that the following assumes that the 'real time' Settlement Period based BSAD includes system to system trades (which are currently not included in the real time BSAD and which are incorporated into BSAD at D+4 Business Days).[4]

In summary, the workaround will comprise BSCCo deriving and publishing (on the BSC Website) the marginal System Buy Price (SBP) for Settlement Periods that fall in the Demand Control Period at D + 2 Business Days.

For each Settlement Period falling within a Demand Control Period on a Settlement Day:

At the Interim Information Run, BSCCo will instruct the SAA to amend the Buy Price Price Adjuster (BPA) to a value that will result in the 'correct' SBP. For each Settlement Run from (and including) the Initial Settlement Run (SF), BSCCo will use the output data from the previous Settlement Run to determine the correct SBP and will instruct the SAA to amend the Buy Price Price Adjuster (BPA) to a value that will result in the 'correct' SBP in the Settlement Run.

It should be noted that this approach means that there will be inaccuracies in the resulting SBP because of the use of the data from the previous Settlement Run, as a result of any data changes between the runs. However, it is believed that the inaccuracies are likely to be relatively immaterial. An additional point to note is that, if this workaround is retained (and not replaced by a BSC System

[3] It should be noted that Modification Proposal P138 'Contingency arrangements in relation to implementation of Demand Control measures pursuant to Grid Code OC6' has since been raised, which seeks to reflect the volumes associated with demand control into the Energy Account of the relevant BSC Party and compensate for the loss of that demand, and to include the volumes in the Net Imbalance Volume derivation. The Panel will consider the Initial Written Assessment at its meeting of 12 September 2003.
[4] The planned implementation date for the fix to include 'system to system' trades in BSAD is 1 September 2003.

solution), then the use of R3 data in deriving the SBP to use at RF could mean that the RF SBP is inaccurate, and this potential should be recognised.

The (high level) solution for Proposed Modification P135 is as follows:

1. Where the Transmission Company instructs demand control in accordance with the Grid Code OC6.1.2 (c), (d) or (e), where such demand control is required for the purposes of insufficient generation to meet demand in real time (and under no other circumstances), the Transmission Company will send, as soon as practicable after the instruction is issued, a System Warning Message to the Balancing Mechanism Reporting Agent (BMRA), stating the time that demand control was instructed (the start of the demand control period), and the GSP Group affected by the demand control;
2. The BMRA will publish the System Warning within five minutes of receipt (current service levels) on the 'System Warnings and other Messages' screen;
3. When the period of demand control completes, the Transmission Company will send, as soon as practicable after the demand control period finishes, a System Warning Message to the Balancing Mechanism Reporting Agent (BMRA), stating the time that demand control finished (the end of the demand control period);
4. The BMRA will publish the System Warning within five minutes of receipt (current service levels) on the 'System Warnings and other Messages' screen;
5. The Transmission Company will also provide a message to BSCCo, as soon as is reasonably practicable following the end of the demand control, informing BSCCo of the demand control period, and providing the start and end time of the demand control. BSCCo will provide this to the SAA for use in Settlement Calculations;
6. The BMRA will calculate the Energy Imbalance Prices **by the current method** at the end of the Settlement Period (as normal) and will report the Indicative Net Imbalance Volume (INIV) and Indicative Energy Imbalance Prices (ISBP and ISSP).

   For the avoidance of doubt, where the Settlement Period falls within a demand control period, and where the INIV is positive, ISBP will be the main price, ***but will have been derived via the current average methodology and will not be marginal****.*
7. For every Settlement Period BMRA will, in the same timescales as the Indicative Energy Imbalance Price calculation (i.e. 45 minutes following the end of the Settlement Period), derive and calculate the Indicative (marginal) System Buy Price, i.e. the SBP had the Settlement Period fallen within a Demand Control Period, and publish this on the System Warnings and Other Messages screen;
8. BMRA will also publish the *increase* in the NIV required to move to the next marginal SBP, and that price, and the *decrease* in NIV required to move to the next marginal SBP and that price (i.e. what the Offer prices either side of the marginal Offer Acceptance in the NIV are);For the relevant Settlement Periods, an indicative marginal price be derived and calculated as soon as practicably possible following the Settlement Period, (preferably to the same timetable as BMRA publication of the Indicative Energy Imbalance Prices).
9. Outside of real time, in preparation for the Settlement Runs, BSCCo will determine what the actual (marginal) System Buy Price would have been for the Settlement Period(s) comprising the demand control period, for monitoring purposes;

10. SAA, when running the Settlement Calculations, for each Settlement Period falling within a Demand Control Period, will derive and report a marginal SBP.

ELEXON are currently exploring the most appropriate, robust, efficient and cost effective way of meeting the requirements set out above. Furthermore, ELEXON will highlight to BSC Parties any potential impacts.

5 PSMG ASSESSMENT OF P135

The following issues have been agreed by the PSMG as the key issues for consideration in the assessment of P135. These have been taken from the stated aims / results / principles of the Modification Proposal, and from the discussions at the PSMG meetings of 6 and 13 August and 2 September 2003.

It should be noted that the consultation responses identified a number of additional issues for consideration by the PSMG, and these issues (and the PSMG considerations in respect of them) are provided in section 8 of this report, with the summary of the consultation responses.

It should be noted that the PSMG have not reached any quantitative conclusion on the effects of P135 in respect of these issues, as it is impossible to do so, as the effects are behaviour based, and thus cannot be quantitatively assessed.

However, a large majority PSMG have made a qualitative assessment of their perception of the effect of P135 on behaviour of Parties and in relation to the arguments set out against these issues, and have concluded that the detrimental effects of P135 (as set out in the counterarguments – the 'no's' below) outweigh any benefit, for the reasons set out in the counterarguments, and thus have determined that P135 does not better facilitate the Applicable BSC Objectives than the current baseline, and therefore P135 should not be made.

A minority of the PSMG (including the Proposer) believe that P135 will better facilitate the Applicable BSC Objectives than the current baseline for the reasons set out in the arguments for P135 (the yes's below).

5.1.1 Marginal Price Assumptions

The PSMG discussed the likely magnitude of the SBP during demand control periods. The PSMG attempted to assess incentives and likely behaviour of Parties (which will be reliant on their perception of the magnitude of the SBP during periods of demand control).

The PSMG noted that no accurate assessment of the likely price could be undertaken, as it is impossible to determine behaviour at times of system stress, and the price will depend on many factors that cannot be assessed in advance. However, the PSMG did undertake some assessment in order to explore the likelihood of a marginal price set at the maximum Offer price (£100,000 / MWh).

The Proposer provided the PSMG with historical analysis of what the marginal Energy Imbalance Prices would have been had the Energy Imbalance Prices been marginal in the period April 2002 to June 2003, provided in Annex 1a. The Proposer noted that this analysis was limited to historical data, which has the limitation of not being reflective of future behaviour, and furthermore, that the Energy Imbalance Price derivation was approximated by use of a simplified mechanism, and therefore the resultant prices are intended to provide only an indication of the general differences between an average Energy Imbalance Price methodology and a marginal methodology.

The PSMG considered the range of Offer prices that could come into play in a demand control period and noted that the maximum marginal price could be £99,999.9999 (£100,000), i.e. the maximum allowable in the data item field. The PSMG noted that there is no way of 'turning off' Bid and Offer prices, as once submitted, they must always be submitted as they cannot be set to null. Some Parties are using £99,999 as an indication to the Transmission Company that they do not want the Bid or Offer (at that price) to be taken.

A number of the PSMG expressed the opinion that during the lead up to demand control, a number of these Offers (with 'feasible' dynamics) might be called in order to mitigate the demand control. Furthermore, a number of the PSMG indicated that if there were to be the potential for an SBP of £100,000 / MWh, Parties could offer in at that price in an attempt to offset the potential exposure to imbalance if they tripped whilst delivering the Offer (thus exacerbating the potential for a marginal price of £100,000).

Some PSMG members were concerned that Parties might offer in at £100,000 in anticipation of demand control being imminent, and thus their Offer being taken. However, it was noted that this may mean that the Offer would only be taken during times of demand control. Whereas a decision to offer in a lower price could mean that these Offers are taken far more frequently.

Furthermore, the Transmission Company (between the meetings of the 6 and 13 August) looked at a 'snapshot' of data and confirmed to the PSMG that all the Offers with an associated price of £99,999 were infeasible. This was due to the dynamics provided with the Offer, for example the Notice to Offer was beyond the Balancing Window (i.e. 90 minutes or more), which makes the Offer untenable for the Transmission Company (Balancing actions have to be taken in the Balancing Window, from Gate Closure to the end of the Settlement Period, so the notice to deliver must be 89 minutes or less). The Transmission Company noted that the highest priced Offer with feasible dynamics (i.e. which could be taken) was £5000 / MWh at the time of looking at the data.

5.1.2 Incentives to Balance

Does P135 incentivise Parties to further balance their position ahead of Gate Closure?

The PSMG assumed that the marginal price will be much greater than the average price at times of demand control (noting that, by definition, the marginal price must be equal to or greater than the average price).

A number of the PSMG noted that there is no explicit incentive to balance in the Applicable BSC Objectives, although it was noted that it can be implicitly linked to efficiency, i.e. an assessment as to whether it is more efficient to balance. The PSMG further noted that previous Ofgem decisions on Modifications (for example Approved Modification P78) have indicated that Ofgem's view is that Parties should be strongly incentivised to forward contract to balance their position ahead of Gate Closure.

An integral part of the decision as to what volume to forward contract for is a demand forecast. Suppliers can effectively only average demand over the Settlement Period and therefore cannot really respond to TV pick up, and other very short term events, other than by reflecting that in the Settlement Period average. Therefore the accuracy of the demand forecast that Suppliers are contracting to is paramount. It was noted that on 10 December 2002 (a day where the system was put under stress, and demand control was imminent) the Transmission Company demand forecast (on the BMRA) was 5% under the actual demand, thus understating demand. Supplier demand forecasts are likely to be less accurate than the Transmission Company's, as Suppliers do not have as complete a view of the market as the Transmission Company.

A number of the PSMG supported the requirement for better real time reporting of actual demand data (at GSP Group level) by the Transmission Company, and this requirement is discussed further in issue 20, section 8.3.

A number of the PSMG stated that a potential effect of P135 would be to incentivise length in the market, i.e. Parties would go (very) long to protect themselves from the risk of exposure to the System Buy Price, thus creating a level of reserve. This was considered by some to be inefficient, as each individual Party will go long by 5 – 10% (i.e. holding their own reserve), thus collectively over contracting by 5-10%, whereas it could be considered to be more efficient for the Transmission Company to obtain the reserve for Parties, i.e. one body buying the reserve. It should be noted that a number of PSMG believe that the ideal solution would lie somewhere between these two extremes.

Another view of some of the PSMG is that the incentives should be on each Party to 'insure' themselves by forward contracting in sufficient volumes to cover peak periods, with the Transmission Company undertaking the residual balancing in real time. Thus, to achieve this incentive, pricing signals (from the Energy Imbalance Prices into the forwards markets) should be strong enough to indicate what the market is 'doing', i.e. entering a period of stress or surplus.

Furthermore, some of the PSMG believe there to be an issue with Suppliers 'free riding', i.e. a Supplier assuming that all Suppliers will go long, and effectively get the required reserve, so that Supplier goes short saving themselves the cost of the reserve and exposing themselves to a relatively 'neutral' price. P135 seeks to ameliorate the 'free riding' effect, where a number of Suppliers are short, culminating in the system ending up short, and thus address this by attempting to target the costs of being short in a more appropriate manner.

The PSMG noted that incentives to (further) balance will be driven by a number of factors. These are all interrelated, and will all form part of the assessment of a Party as to their incentives and thus resulting behaviour:

- The strength and timeliness of the pricing signal:

  Demand control is not reflected in the NIV, and so an incorrect SBP will be derived as well as there being a potential for an increased number of Bids at the time of demand control (to exactly match generation to demand when demand falls off), which is not offset by an Offer volume representing the level of demand control (discussed in section 4.2).

  Thus where the market remains short (accepted Offer volume > accepted Bid volume), then the increased number of Bids may weaken the marginal price, by tagging more from the Offer stack leaving less expensive Offers. In more extreme cases, the market may in fact go long under these circumstances, where accepted Bid volume > accepted Offer volume, and the price signal may be removed in entirety, as the System Sell Price becomes the main price, which is derived by an average.

  Furthermore, a number of the PSMG believe that if a marginal price is used only during periods of demand control, that the associated price signal is lost. They assert that if marginal prices are limited to periods of demand control only, then the market will discount the potential for high imbalance prices by the extremely low probability of those prices actually being realised, and thus the relevant market signal will not emerge in a timely manner.

  This could mean that Parties would not respond to the signal of impending shortage (as it is not there), or that when the signal does emerge, it is too late to respond to it, as demand control occurs in the Balancing Window. Thus if demand control occurs, Parties could be exposed to a marginal price when it is too late to react and contract ahead of Gate Closure.

In terms of the (longer term) strength of the pricing signals from P135, a number of the PSMG raised the question as to how much the Energy Imbalance Price will have to rise to incentivise forward contracting, in turn raising prices on the forwards markets sufficiently to incentivise generation to come on.

It could be argued that if demand control periods are short and the effect of demand control is limited, then the effect on the forward curves will be small, and the requisite price signal could be muted / not in evidence, and the requisite effect of P135 is lost. Conversely, if the effects of demand control are considered to be large, then the forward curves will reflect this effect, with the price signal clearly in evidence, having the required effect. A number of the PSMG believe the former to be the most likely outcome of P135, with the marginal price only in times of demand control having no effect in the forwards curve and thus failing to incentivise forward contracting and plant to come on.

The PSMG noted that a marginal price over the entire winter peak could have sufficient effect on the forwards curves, to create the incentive for plant to return to service. Furthermore, it was the view of some PSMG members that long term price signals are required (i.e. signals now) to get Parties contracting at the required levels to cover the winter peak, as they raised concerns that P135 introduces only short term signals that will come too late to get the forward contracting going, and plant on the system for the winter peak. The Transmission Company can only instruct to the level of available physical generation, and thus if there is insufficient generation, there will be a problem for the Transmission Company balancing the system. Thus it could be argued that the incentives to get more generation on the system must be there over the long term.

It was noted that an associated issue is the type of plant that is showing as unavailable for this winter. P135 may benefit reliable peaking plant, and incentivise that sort of plant to come on this winter (assuming the incentive is there). However, if the unavailable plant is not reliable peaking plant, then the issue of insufficient generation may persist.

- The perception of the risk of demand control – if a BSC Party believes the risk of demand control occurring / being short during a period of demand control, to be small, then their incentives will be different to a Party that believes the risk is higher.

  One PSMG member noted that the perception of risk, and the associated incentives could be driven by the type of demand reduction initiated. The PSMG member noted that if other types of demand reduction (besides demand control under OC6.1.2(c), (d) and (e)) were utilised (such as those under the Electricity Supply Emergency Code) in response to (relatively long term[5] in comparison to demand control under OC6.1.2 (c), (d) and (e)) indications that there is insufficient generation to meet demand, then the marginal SBP associated with demand control under P135 would not apply to these other types of demand reduction. This will incentivise Parties differently to when demand control (covered by P135) is initiated by the Transmission Company.

- The perception of the risk of exposure to Imbalance charges - Parties may take a view that the risk of exposure to a marginal price at times of demand control could be offset by any return via Residual Cashflow Reallocation Cashflow (RCRC). The assumption is that where there is a high marginal price (and Parties are, in general, short), the BM cashflows will be over recovered, and the residual cashflow will be high. This could mean that Parties may recover a 'lump' of the exposure to imbalance paid at SBP back from RCRC, reducing the overall cost of imbalance.

[5] i.e. not within the Balancing Window of 90 minutes, but perhaps in response to indications of a more pervasive shortage.

However, some of the PSMG noted that RCRC could be considered to be a side effect of the Settlement calculations. Furthermore, one which is unpredictable as even when the market is generally short, the relative sizes of the System Sell Price (SSP) and SBP could lead to the RCRC being a debit, rather than a credit. Therefore, the inability to predict the RCRC may mean that it has little influence on Parties incentives.

Thus, in summary:

YES:

- Marginal System Buy Price during times of demand control sends a stronger signal to Parties to be able to balance, in particular not go short and be exposed to SBP;

- Even where a Supplier is directly affected by the reduction of their metered demand under demand control (say in one GSP Group), their overall 'pre-demand control' imbalance position is unlikely to be changed significantly by demand control, as it is not applied nationally. Therefore a Supplier's imbalance position is unlikely (except in marginal cases) to be 'flipped' from short to long by the application of demand control; and

- Furthermore, a Supplier is unlikely to be aware in advance as to where and how demand control will be applied and thus is unlikely to take the risk of deliberately going short in the expectation that their (short) imbalance position is ameliorated by the demand control.

NO:

- Marginal System Buy Price during times of demand control will incentivise (most) types of Generator to withhold generation from the market in case of trip;

- Marginal System Buy Price only during times of demand control means that the signal of system stress, and the associated incentive to balance comes too late for parties to react by contracting ahead of Gate Closure;

- Furthermore, lack of timely / sufficiently strong pricing signals to Parties (i.e. well in advance of times of system stress) will not provide price signals sufficient to incentivise plant to return to service in time to meet the peak demand;

- Demand control that does not have a volume reflected in the NIV will result in an incorrect NIV and thus SBP derivation, and without it, NIV may be lessened / outweighed by Bids taken to match generation to demand following demand reduction. This may send the market long, further weakening the price signal / creating perverse incentives, as the System Sell Price becomes the main Energy Imbalance Price;

- Demand control that is not reflected in Suppliers imbalance positions may have the effect of sending short Suppliers long, and long Suppliers longer, thus exposing them to System Sell Price and so reducing the effect of a marginal SBP and incentives on Suppliers to balance ahead of Gate Closure; and

- A marginal imbalance price only in one direction will incentivise length, not balance (noting that even with an average price, the risk averse strategy is to go long to avoid exposure to System Buy Price, a marginal SBP may just have the effect of increasing that length).

5.1.3 Security of Supply

Does P135 improve security of supply? (noting that this issue is heavily related to the issue in respect of incentives to balance).

One PSMG member believed that, in order to understand the requirement for P135, and its impact on security of supply, the 'do nothing' situation needs to be understood. A number of PSMG members questioned why the Transmission Company is not buying reserve for this winter, as they felt that this would be a solution to the issue of pending demand control, within the current arrangements.

However, the Transmission Company assert that their role is as *residual* balancer of the system, and therefore it is not their role or responsibility to buy reserve to cover the (long term) imbalance position of Parties. The Transmission Company therefore believe that the most appropriate instrument to ensure that generation meets demand this winter (and coming periods of peak demand), and thus to assist in securing supply with respect to energy balancing, is appropriate pricing signals, thus ensuring that Parties can respond and cover their positions.

However, a PSMG member noted that the Transmission Company is unaware of the imbalance positions of BSC Parties, and that the role of the Transmission Company is perceived to be one of matching generation to demand in real time. Thus there is a perception that the Transmission Company procuring / obtaining greater levels of reserve would ameliorate the defect that P135 is seeking to address.

Thus this issue relates to the arguments made in 4.1.2 (as to the behaviour of Parties as a result of P135 price signals). If Parties are incentivised to forward contract to cover themselves at times of peak demand, thus making more generation available than is currently forecast, then it could be argued that security of supply is improved.

However, if the perceived risk of exposure to extreme marginal SBP during periods of demand control is too high, then generators may 'self insure' by withholding generation to insure against trip, thus exacerbating the shortage of generation, potentially degrading security of supply.

It was noted that at times of system stress plant may be more likely to trip. For example where the plant is responding to an Offer from the Transmission Company, close to maximum generation capacity with the plant under stress. If the plant trips, not only does the plant incur non delivery on the accepted Offer(s), but it will incur SBP for the full extent of the contracted volume that plant was generating to meet (all or part of). Where the SBP is high, this could have a major effect on the generator.

The perception of this risk may be factored by the generator into the associated Offer price at that time. However, the risk may be considered to be too great by some.

Other factors, discussed in 4.1.2, will also influence security of supply, namely the behaviour of Parties in responding to the incentives of P135.

In summary:

YES:

- Marginal System Buy Price during times of demand control sends a stronger signal to Parties to ensure that they are able to balance and avoid exposure to SBP. This promotes trading in the forwards markets which will ensure that there is sufficient generation available to meet demand, avoiding the requirement for demand control.

NO:

- The current trading arrangements are adequate in respect of security of supply;

- Marginal System Buy Price during times of demand control will incentivise Generators to withhold generation from the market in case of trip. This could have the effect of exacerbating the requirement for demand control; and

- Assuming withheld plant, a marginal System Buy Price could incentivise Generators that trip in a period near to / during demand control to breach the Grid Code by bringing on withheld plant to meet their contracted position in order not to be short. This may increase operational issues for NGC;

5.1.4 Other Incentives from P135

Are there any other incentives on Parties that P135 may introduce, and are these beneficial or detrimental, and is there a trade off in any direction?

The PSMG did not believe there to be any further incentives from P135 that have not already been explored (at 4.1.2).

Some PSMG members reiterated that there may be perverse incentives on Suppliers resulting from demand control, (depending on the effect of the volume reduction), as the removal of metered volume as a consequence of demand control may send a short Supplier long, and a long Supplier longer. Some PSMG members believed that this is a consequence of the (current) treatment of demand control, not the defect in P135.

5.1.5 P135 and the Likelihood of Demand Control

Will the implementation of P135 decrease the likelihood of demand control?

The PSMG noted that the perception of whether P135 is likely to decrease the likelihood of demand control depends on the perception as to whether the pricing signals are strong enough and timely enough to influence the long term behaviour of Parties (section 5.1.2).

In summary – yes; if Parties respond to P135 by forward contracting and incentivising the availability of more generation, and no; if Parties respond to P135 by withholding generation to self insure against the risk of exposure to a marginal System Buy Price if they trip during a demand control period.

5.1.6 P135 as the 'Correct' Mechanism

Is P135 the correct mechanism for dealing with the problem of potential generation shortage this (and coming) winter? Is there a different way of ensuring that generation matches demand?

Covered by previous arguments at 4.1.2 and 4.1.3, namely that Parties should forward contract in sufficient volumes to cover themselves at times of peak demand (implying more generation comes on in response) and price signals are the way to achieve the incentive to contract.

In summary – yes, if it is believed that P135 will send sufficiently strong price signals, in a sufficiently timely manner.

No, if it is believed that:

- There are other ways to ensure that generation meets demand;

- The price signals from P135 will be too weak and too late to respond by forward contracting;
- The incentives on Parties are such that they will not respond to P135 by forward contracting (for example the perception of risk).

5.1.7 Marginal vs Average Pricing

All Parties in imbalance in the same direction as the system energy imbalance (Net Imbalance Volume) are contributing to the cost of the marginal energy balancing action (as it is not possible / appropriate to determine any energy apportionment), and therefore the Energy Imbalance Price applied should be marginal. Is this true? Or is average pricing more appropriate for the electricity market?

This issue, again, depends on the perception of what the Energy Imbalance Prices are seeking to achieve and whether average or marginal prices send the most appropriate signals to the market. These arguments are set out in previous sections.

5.1.8 Potential for Market Manipulation

The perception could be that a marginal pricing methodology could be open to gaming (as was the perception under the Pool), and thus an average methodology would mitigate gaming. Is the potential for gaming present under P135?

The PSMG noted that the perception of gaming under the Pool arose as a consequence of Generators being *paid* the marginal price for generating. Under the current trading arrangements, Parties are paid as bid in the Balancing Mechanism and pay the marginal SBP for (short) Energy Imbalances, and therefore the opportunity for gaming is greatly diminished. The majority of the PSMG did not believe gaming to be an issue for P135.

5.1.9 Definition of a Marginal Price

Is the definition of a 'marginal' price in the Proposed Modification appropriate, or is a different definition (alternative Modification) more appropriate, and (if appropriate) does the benefit of getting P135 implemented for this winter outweigh any 'purist' arguments with respect to a marginal price?

The view of the PSMG is that the Proposed Modification is quite clear as to the marginal price, namely the most expensive Offer Acceptance (or part of) that remains in the NIV. The PSMG believe that this is an appropriate mechanism for setting the marginal price for P135, given the limited circumstance of application.

5.1.10 Credit Cover Arrangements

Is Credit Cover under P135 any more of an issue than under the current arrangements?

The PSMG noted that derivation of a marginal SBP during periods of demand control could introduce extreme Energy Imbalance Prices, consequentially increasing the risk of Parties going out of business (depending on the magnitude of the SBP and the size of the Energy Imbalance).

A number of the PSMG therefore raised concerns regarding the ability of the current Credit Cover arrangements to protect BSC Parties from a Party default in respect of potentially material imbalance liabilities, which may far exceed the Credit Cover lodged by that Party.

As an extreme example, a single site generator, contracted for 500 MWh, trips during a period of demand control where the SBP is extreme – say £10,000, the generator incurs a £5,000,000 imbalance charge for the Settlement Period, and receives no RCRC to offset this against, as the metered volume was zero for that Settlement Period.

However, the PSMG noted that this is effectively no different to now, in that high Energy Imbalance Prices could occur with a significant impact on certain Parties. However, the PSMG felt that the implementation of P135 had the potential to increase the frequency of an extreme SBP.

It was noted that ELEXON have a requirement to set an appropriate Credit Assessment Price (CAP) used in the calculation of Energy Indebtedness for Parties and that any change to the general trend of Energy Imbalance Prices will require amendment to the CAP. Normally assessment of the CAP is based on operational experience of the Energy Imbalance Prices.

The potential for Party default as a consequence of extreme Energy Imbalance Prices exist currently. Therefore the majority of the PSMG agreed that their concerns regarding the potential for BSC Parties to be exposed to the consequences of a Party default, in conjunction with the potential for P135 to exacerbate the circumstances under which this may occur, should be highlighted in this report. No further consideration of the implications of P135 on the Credit Cover arrangements will be undertaken as part of P135.

5.1.11 Risk Management: Insurance Products

Will the implementation of P135 increase the availability of new / existing insurance products for covering the risk of exposure to an extreme System Buy Price?

A number of PSMG members noted that, since P135 implements a marginal SBP during periods of demand control, there is currently no insurance product available to hedge / address this risk, as a consequence of the event occurring after Gate Closure. A number of the PSMG believe that this may prevent the emergence of appropriate insurance products. Conversely, the implementation of P135 could create a market suitable to the emergence of such insurance products.

6 STATEMENT OF URGENCY

The Modification Proposal states, as justification for the Proposal and for the request for Urgency, that:

"The calculation of the 'main' energy imbalance price, using a marginal methodology, will provide more appropriate price signals to incentivise Market Participants to contract forward in order to mitigate the risk of not being able to balance at Gate Closure. This is because marginal pricing provides an undiluted signal to the market as to the underlying cost of supplying the last increment of energy required to balance generation and demand. It is particularly important that imbalance prices provide appropriate signals in times of energy shortage, as weakened signals could threaten security of supply. In this respect the modification proposal will better facilitate the applicable BSC objective (b) the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System.

Times of energy shortage are most likely to be seen over the winter period (starting post October clock change) as this is when the peak demand for electricity is greatest. As the defect to be addressed potentially affects security of supply during these times, Urgent status is requested for this Modification Proposal in order to implement the new methodology and provide more appropriate signals to the forward markets in the shortest possible timescale, lowering the risk that customer demand control measures will be required this winter.

The proposed change to the 'main' energy imbalance price calculation is limited to SBP during "Periods of Demand Reduction" only, so that implementation could potentially be achieved as soon as possible.

It is anticipated that the risk of exposure to a marginal imbalance price during these periods should improve incentives to market participants to contract sufficiently so as to reduce the risk of such demand control measures becoming necessary".

7 RATIONALE FOR PANEL RECOMMENDATIONS

The Panel agreed with the recommendations and the rationale set out by the PSMG. The Panel unanimously agreed that Proposed Modification P135 should not be made.

8 SUMMARY OF REPRESENTATIONS

8.1 High Level Summary

Twenty five responses (57 Parties and 5 non Parties) were received in respect of the consultation on Urgent Modification P135. Two of the consultation responses (2 non Parties) are confidential, and these responses will be forwarded separately to the Authority, but are summarised in section 8.4.

It should be noted that the Transmission Company provided a response to this consultation, as the Proposer, and this response is included in the totals below. The Transmission Company also provided Transmission Company analysis (see Annex 5).

Proposed Modification P135:

- 3 respondents (3 Parties, including the Proposer) supported P135;
- 21 respondents (53 Parties, 5 non Parties) did not support P135; and
- One no comment response.

Alternative Modification P135:

The options covered below, namely options (a) and (b) relate to options considered by the PSMG as potential Alternatives. For information, option (a) is P135 Proposed, plus marginal SBP as the Offer price for all Accepted Offers in a period of demand control and option (b) is P135 Proposed, plus inclusion of the volume deemed to have been delivered by demand control in the Offer stack for NIV Tagging.

- Of the 3 respondents that supported P135:
  - One respondent (1 Party – the Proposer) did not support any Alternative; and
  - Two respondents (1 Parties) supported an Alternative comprising option (b) only, as neither supported the inclusion in the Alternative of option (a).
- Of the 21 respondents that did not support P135:
  - Six respondents (7 Parties, 2 non Parties) did not make any comment in respect of potential Alternatives comprising option (a) and / or option (b);
  - Six respondents (18 Parties, 1 non Party) did not support there being any Alternative to P135;
  - Seven respondents (16 Parties, 2 non Parties) believe an Alternative comprising options (a) and (b) to be better than the Proposed Modification, but not better than the current baseline; and
  - Two respondents (12 Parties) believe an Alternative comprising option (b) (only) to be better than the Proposed Modification, but not better than the current baseline.

A number of respondents raised their own ideas for potential Alternatives and these are explored in the following section.

8.2 Additional Options for an Alternative

A number of additional options were proposed (some of which fall beyond the scope of the Code) and these are listed below. The PSMG at their meeting of 2 September 2003, considered these options for a potential Alternative, and their considerations are set out below:

1. NGC to make capacity payments for generators;

   The PSMG noted that this is beyond the scope of the Code and therefore could not be considered further.

2. NGC to procure reserve via contracting ahead;

   The PSMG noted that this is beyond the scope of the Code and therefore could not be considered further. However, a number of the PSMG noted that this is effectively the current baseline.

3. Generation plant loss after Gate Closure to be considered and protected from marginal SBP in some way (in order to prevent generators from withholding capacity);

   The PSMG noted that treatment of / compensation for plant loss after Gate Closure could have the effect of incentivising (less reliable) generation to come into the Balancing Mechanism at times of demand control, rather than withholding generation for self balancing in case of trip or withholding generation to avoid trip. However, the PSMG agreed that this was effectively beyond the scope of P135 and was a different Modification.

4. A SBP derived from the average of all balancing actions on the Offer stack, with no CADL and no NIV Tagging applied (only Arbitrage and De Minimis Tagging applied), i.e. based on the assumption that all Offers in a Settlement Period are taken for energy balancing purposes;

   The PSMG believed that this was worthy of further consideration as a potential alternative to P135. Therefore this potential alternative is discussed further in Annex 6.

5. Reversion of the calculation of the SBP to pre-P78 mechanism;

   The PSMG believed that this was worthy of further consideration as a potential alternative to P135. Therefore this potential alternative is discussed further in Annex 6.

6. Withdrawal of the ability of NGC to forward contract at times of demand control; and

   The PSMG noted that this is beyond the scope of the Code and therefore could not be considered further.

7. Cap SBP to an undefined amount (say £2000 to £3000) considered to be representative of to maximum cost of energy Parties are willing to pay for, or cap SBP to the Value of Lost Load (VOLL) for Suppliers only, or cap SSP to SBP.

   The PSMG considered the possibility of placing a cap on the marginal price, as well as implementing an administered price. The PSMG believed that these options were worthy of further consideration as potential alternatives to P135. Therefore these potential alternatives are discussed further in Annex 6.

8.3 Additional Issues for Consideration:

A number of additional issues were raised in respect of P135 by the consultation responses, and these are broadly summarised below (the response number is provided for information):

1. Credit cover – a number of responses felt there to be insufficient 'comfort' in respect of credit cover should the SBP be extreme;

   The PSMG noted that this issue had been considered previously by the PSMG (covered in section 5), where the majority of the PSMG had agreed that Credit Cover would not be considered further under P135.

   However, when discussing this point, the PSMG noted an additional issue which is linked to credit cover implications, namely that if there is a demand control period and a Party is aware that it will be exposed to the SBP (because of plant trip, or other reason), that Party (the 'affected Party') may try to trade out of the imbalance before the next Gate Closure. Other Parties may decide not to take the risk and trade, in case the 'affected Party' cannot meet its contract liabilities as a consequence of its potential imbalance liabilities.

   Thus the 'affected Party' cannot trade out its imbalance for subsequent Settlement Periods (which may also be in a / the Demand Control Period), and is exposed to SBP for its imbalance in those Settlement Periods, and this may exacerbate the catastrophic financial effects on the 'affected Party'.

   Therefore, a number of the PSMG felt it appropriate to reiterate their concerns that implementation of P135 is considered to materially raise the risk to Parties. Namely the risk of P135 initiating a default from exposure to large imbalance prices at times of demand control, and the risk to other Parties from this occurring where the affected Party has insufficient credit cover in respect of its imbalance liabilities.

2. A number of responses raised concerns regarding the timing of the raising of P135, and consider that it should have been raised earlier in order to allow a more extensive assessment;

   The PSMG noted this and recognised the constraints of the timetable agreed for the Urgent Modification.

3. P78 – a number of responses felt that P78 either sends correct price signals, or should be allowed to run through the winter in order to determine what the real amendment to pricing should be;

   The PSMG noted that assessment of P135 in respect of the assessment issues identified (section 5) and against the Applicable BSC Objectives would cover this point, as P135 would be assessed in terms of whether it is the 'right' Modification, and against the current baseline.

4. The interaction between NGC instructed demand control and Transco invoked gas interruptions affecting CCGT (response 1);

   The PSMG noted that there is an interaction, as it is the generally stated position of the gas industry from a safety point of view, that electricity should be interrupted before gas, as a gas disconnection may take months to get back on. Therefore the PSMG noted that there may be a likelihood of Transco / the Transmission Company 'switching off' CCGT plant in order to prevent a gas interruption. This may happen coincidentally with periods of demand control, as the system could be under stress.

5. Mixed signals from NGC regarding shortages this winter (responses 8 and 13 particularly);

   The Transmission Company representative on the PSMG noted that the 'message' from the Transmission Company in relation to potential shortages this winter had been consistent. Furthermore it was onwards interpretation that has mixed the message. The Transmission Company representative indicated that the Transmission Company has been consistently indicating that there is sufficient generation to meet demand at the winter peak, but that there is insufficient generation to meet demand plus operating margin (OPMR) (the amount of generation over and above forecast demand required to meet a Loss of Load expectation of one occasion per year).

   The Transmission Company representative noted that a normal winter peak operating margin is in the region of 7GW and that this 7GW operating margin gives a statistical probability of a loss of load of 1 in 365 (i.e. 1 day in 365), i.e. that allowable under the planning / operational standard. Thus if the 7GW operating margin decreases, this consequentially impacts the statistical probability of the loss of load. In the present case, the decrease in the operating margin has meant that the statistical probability of loss of load has increased over the allowable 1 in 365.

   Therefore, by implication, P135 seeks to increase the available generation (by sending the relevant price signals) and thus increase operating margin such that the 1 in 365 target is met / exceeded.

   A number of PSMG members noted that, as a related issue, it could be useful to be able to see the Transmission Company's estimate of operating margin on a dynamic basis, as it may influence a Party's behaviour by indicating the probability of a demand control event, as well as the potential level to which a Party may have to contract to protect itself from such an event.

   The Transmission Company representative noted that the operating margin can be determined from the Surplus forecast data published on the Balancing Mechanism Reporting Service (BMRS), where 2 – 52 weeks out a weekly figure is published, and 1-14 days out, a daily figure is published.

   Conversely a PSMG member noted that Parties should be determining their own probabilities of events in order to ensure contract cover, and questioned whether access to the Transmission Company's forecast would influence Party behaviour at all, in terms of contracting for more, or 'un-mothballing' plant, and therefore argued that this point is not relevant to P135.

6. Demand control not in NGC incentive scheme (response 9);

   The PSMG noted that demand control is not taken into account in the Transmission Company incentive scheme. However, this issue is not within the scope of P135, and the Code.

7. Issue relating to amending the treatment of generation plant loss post Gate Closure in order to incentivise generators to offer spare capacity (response 10);

   The PSMG noted that treatment of / compensation for plant loss after Gate Closure could have the effect of incentivising (less reliable) generation to come into the Balancing Mechanism at times of demand control, rather than withholding generation for self balancing in case of trip or withholding generation to avoid trip. However, the PSMG agreed that this was effectively beyond the scope of P135 and would not be considered further.

8. More exploration of the likely offer prices and generator behaviour (response 12);

   The PSMG noted that consideration of this issue had been undertaken by the group (see section 5.1.1) and that no further useful exploration by the group could be undertaken.

9. Exploration as to whether there is a need to strengthen existing incentives to balance (response 12);

The PSMG noted that consideration of this issue had been undertaken by the group (see section 5.1.2) and that no further useful exploration by the group could be undertaken.

10. The impact of any amendment to the RCRC on competition, specifically in respect of windfall payments (response 12) and whether RCRC / more extreme BSUoS would mean that balanced parties run at a loss (response 16);

    The PSMG noted that consideration of this issue had been undertaken by the group (see section 5.1.2) and that no further useful exploration by the group could be undertaken.

11. Exploration as to whether there is time for the development of risk management products in time for this winter (response 12);

    A PSMG member believed that there would not be any development of risk management products for P135 at all, mainly as a consequence of the effects of P135 coming post Gate Closure. This, in the opinion of the majority of the PSMG, may effectively stop any development of a product to mitigate the risk of (post Gate Closure) exposure to imbalance, as P135 makes the risk higher, and thus harder to manage.

    It was noted by one PSMG member, that the Transmission Company may offer contracts outside of the Balancing Mechanism which cover trip risk within the balancing window, but not in bulk.

12. Issue as to whether the risk associated with exposure to high imbalance costs under P135 makes a case for reviewing the ability to make ex post contract notifications in order to mitigate the otherwise potentially unmanageable risk (response 17);

    The PSMG noted that this issue is related to issue 11 above, in terms of ex post notification being a risk management tool. One member of the PSMG noted that one point of view could be that if P135 is to work, then there needs to be ex-post notification. The rationale for this viewpoint is that it could be considered to be inefficient for each Party to hold reserve, whereas ex post notification allows the market to hold an aggregate reserve, which could be considered to be more efficient. The PSMG noted that an appropriate balance between individual and aggregate reserve would need to be struck to maximise efficiency, and further noted that P135 could be considered to push the balance of reserve further toward the market, and individual participants, than the current baseline.

    However, the PSMG noted that ex post notification does not form part of P135, and therefore should not be considered further.

13. Issue as to the appropriateness of implementing a partial solution to the problem (response 15);

    The PSMG noted that this issue is related to the previous discussions of the scope of P135, and the associated drawbacks of P135. These discussions are provided in sections 4.2 and 5, and therefore no further comment is made here.

14. Issue as to whether the mechanism proposed by P135 is appropriate – pre P78 prices were volatile / spiky, and plant was still being mothballed, so why would P135 have the required effect (response 15);

    The PSMG noted that the pre P78 pricing mechanism meant that the reverse price was often volatile and 'spiky', not the main price and therefore this point is not relevant to P135.

15. Previous modifications have been attempting to reduce the volatility and spread of the Energy Imbalance Prices, and P135 (as well as P136 / P137) seem to be reversing this, why? (response 15);

    The PSMG noted that previous Modifications were addressing volatility and 'spikiness' in the reverse price, not the main price and therefore this point is not relevant to P135. Furthermore, a number of PSMG members noted that differences in volatility and spread are a consequence of any pricing mechanism, not a justification as to the efficacy of the pricing mechanism in question, such that if the pricing mechanism is 'right', then any volatility / spread that arises as a consequence of the pricing mechanism must be acceptable, i.e. it is not appropriate to define a certain tolerance of volatility and an acceptable amount of spread in order to choose a pricing mechanism that 'fits'.

16. Issue as to whether there is a defect – response argues that there is no defect unless then Code states that all demand must be satisfied regardless of the cost (response 16);

    The PSMG noted that the Code does not state this, but that the issue is whether a marginal cost is representative, and this is explored in section 5.

17. Issue as to the appropriateness of a marginal price in respect of the decision letter on P78 specifically in relation to Ofgem deeming the use of the first BOA in setting the reverse price to be inappropriate (response 16);

    The PSMG noted that the Ofgem letter was making reference to the appropriateness of the use of the first Bid – Offer Acceptance on the reverse stack setting the reverse Energy Imbalance Price. The NIV Tagging mechanism means that effectively the reverse stack is deemed to have been taken for system purposes and therefore it is not appropriate to use a system balancing action when setting the Energy Imbalance Price.

    Therefore the PSMG agreed that under P135, the use of the marginal Offer Acceptance in the Net Imbalance Volume, means that, by definition, the balancing action is energy balancing (as the Net Imbalance Volume is deemed to be all energy balancing), and thus appropriate to set the main price, if a marginal methodology is the appropriate methodology to have.

    Therefore the PSMG did not believe this point to be relevant.

18. Issue as to whether it is appropriate to artificially remove 'shorts' from a commodity market, thus interfering with normal market signals (response 16);

    The PSMG noted that the concept of security of supply does not 'fit' with a commodity market, and therefore this point is not believed to be relevant.

19. Issue as to whether NGC buying capacity ahead of Gate Closure affects the ability of Parties to contract for that capacity (and produces artificial SSP and SBP);

    The PSMG noted that this aspect of the trading arrangements is an integral part of the market and is also beyond the scope of P135 and therefore no further comment is made here.

20. Inclusion in the solution of real time reporting of GSP Group demand data (overall demand second to second for each GSP Group) (response 18); and

    One member of the PSMG noted that, if P135 were to be implemented, there are potentially three things that a Party could do to avoid exposure to the risk of the marginal SBP at times of demand control (and potentially avoid demand control (in relation to P135) being instructed at all). These are to maintain plant better, improve demand forecasting and to buy options. The PSMG member noted that the maintenance of plant and the buying of options lies purely within the remit of a Party.

However, the one area that is beyond the ability of a party to resolve entirely, is the improvement of the demand forecasting. Therefore the PSMG member argued that if Parties had access to real time demand data, second by second, from the Transmission Company, by GSP Group, each Party would be able to adjust their own demand forecast in real time, in response to changing circumstances, and be able to react to the changes.

It was noted that Change Proposal 976 'BMRS System Updates' has been raised (and is progressing through the Change Proposal process) in order to increase the frequency at which the following data is published on the BMRA (from 5 times daily, to a Settlement Period based publication), and this enhanced reporting may provide the requisite reporting functionality for enabling reaction to changing circumstances close to real time:

- INDDEM – national and zonal indicated demand;
- INDGEN – national and zonal indicated generation;
- INDIMBAL – national and zonal indicated imbalance; and
- MELNGC – national and zonal indicated margin.

A number of PSMG members questioned whether this enhanced reporting was essential to P135. The majority of the PSMG agreed that, given that there is currently no access to this data, the lack of access makes P135 less manageable. However, the PSMG members noted that access to this data will only make P135 less unmanageable.

21. Issue regarding an undelivered Offer acceptance setting the marginal price (response 19).

The PSMG noted that at the point of taking an acceptance, the Transmission Company have no idea whether that acceptance is delivered or not, it is only the settlement calculations post event that make that determination. Therefore it could be argued that since the acceptance was taken in good faith, that it is appropriate to set the marginal price.

However, the PSMG considered the complexities of determining non delivery for each BM Unit, and then which part of Acceptance was non delivered, and how it would affect the whole of the stack (in terms of removing undelivered volumes from all Offers to get the 'right' volume in the Offer stack). The PSMG agreed that, whilst this issue may be appropriate for consideration as part of P136 and P137, where there is to be a marginal price for every Settlement Period, in respect of P135, and the limited circumstances that P135 is to apply to, it is not considered to be a material issue.

22. Issue regarding the exposure of Supplier Volume Allocation (SVA) registered Exempt Export generation to imbalance under P135, as these Exempt Export generators may be exposed to a higher SBP than other generators, as these Exempt Export generators will get charged SBP + RCRC, whereas generators will get charged SBP – RCRC (confidential responses).

The PSMG acknowledged that this is a feature of some of the commercial contracts in place, that specify 'pass through' of imbalance costs, and RCRC losses, however, it was noted that where an Exempt Export generator with this sort of commercial contract trips, they will be (slightly) better off (or less worse off) than other generators, as they will get an RCRC cash back. However, the PSMG, whilst recognising the issue, noted that the form of commercial contracts is beyond the scope of P135, and the Code.

8.4 Summary of Confidential Responses

8.4.1 Response 1: Licence Exempt Generator (LEG) (Non BSC Party):

Does not support P135 because:

- High prices from P135 cannot be responded to in time, but places high risk on generators tripping at that time, and places costs on all market Participants that are more efficiently borne by the Transmission Company;
- Price signals are too uncertain to incentivise contracting behaviour for this winter;
- The respondent is a LEG who is fully contracted and therefore cannot respond to new price signals, but will be exposed, via pass through, to the Energy Imbalance Prices;

Issues from P135:

P135 imposes costs on market participants that fall disproportionately on LEGs. LEGs trading through SVA do not receive RCRC and may even have to compensate their Supplier for any loss of RCRC through the netting process. Effectively LEGs will be exposed to a higher SBP than other generators (as LEGs will get charged SBP + RCRC, whereas generators will get charged SBP – RCRC). This is believed to be unduly discriminatory;

The respondent recognises the issue P135 is seeking to address, but does not support the mechanism, as it is believed to be a short term measure that has not been thought through, which is believed to be unduly discriminatory;

The respondent believes that both alternative options (a) and (b), are better than the Proposed Modification, as (a) improves the incentives to offer, as well as increasing BSUoS (potentially offsetting the effect of paying out RCRC), and (b) more correctly specifies the marginal price, as well as ensuring that Suppliers (causing the problem) have their imbalance calculated at the pre-demand control volume. However, the respondent does not support an Alternative based on this option.

8.4.2 Licence Exempt Generator (LEG) (Non BSC Party):

Does not support P135 because:

- Price signals from P135 cannot be acted on ahead of Gate Closure, furthermore, it is not clear how such infrequent and short term measures can be reflected in the short term forwards market for the coming winter when there is no experience of the effect it will have;
- The requirement on the Transmission Company to accept all feasible offers prior to calling demand control will lead to extremely high SBP's, and could lead to a reduction in cost reflectivity in the Balancing Mechanism, as Parties imbalance payments are increased, without any increase in the cost of balancing the system, as balancing actions are paid as bid;
- P135 does not encourage Parties to balance, only to go longer (or less short) than they generally were previously. As parties are generally long, P135 will make the system more out of balance, thus reducing efficiency;
- A marginal SBP could be counterproductive (in respect of the stated aims of P135) by resulting in generators choosing to run at reduced load to hedge against generator failure;
- Timing of P135 is too late to influence return from mothball for this winter;

- Competition is reduced by P135, as single site generators are unlikely to have the flexibility to balance by portfolio adjustments, and exposure to imbalance will have a severe financial impact, undermining investment in generation;
- Distributed generation is also discriminated against, as if trading through SVA, they do not receive RCRC and may have to compensate their Supplier for any loss of RCRC through the netting process.

Issues from P135:

Impacts on / implications for distributed generation have not been explored, specifically the exposure of distributed generation to a higher SBP than other generators (as distributed generation will get charged SBP + RCRC, whereas generators will get charged SBP – RCRC).

Alternatives:

The Transmission Company should be encouraged to carry sufficient reserve to prevent the system reaching a point where voltage reduction is required. A mechanism that encourages Supply companies to protect their customers from demand reduction should also be encouraged. The Transmission Company and Suppliers could buy reserve (at a fair market price) from demand side participants willing to suffer voluntary demand reduction, this meets the objectives of P135 without the potentially penal side effects; and

The respondent does not support P135 or options (a) or (b). However, the respondent believes that both (a) and (b) are preferably to P135, as (a) increases incentives to make Offers that would otherwise be discouraged, as a result of the neutral non delivery. Furthermore, the increase in BSUoS costs, potentially offsetting RCRC, reduces the discriminatory effect on distributed generation. (b) is likely to lead to a more correct specification of the marginal price by accounting for the volume of demand control, as well as ensuring that Suppliers (causing the problem) have their imbalance calculated at the pre-demand control volume.

9 SUMMARY OF IMPACT ASSESSMENTS

It should be noted that the BSC Central Service Agent, Transmission Company and ELEXON were requested to impact assess the Proposed Modification P135, as well as a potential alternative comprising options (a) and (b) (set out in Annex 6). Since the PSMG have not recommended an Alternative Modification, the impacts provided for the potential alternative are excluded from the summary below (but are provided in the full impact assessments, Annexes 3, 4 and 5).

9.1 BSC Central Service Agent

The full impact assessment is provided in Annex 4.

Manual Solution:

Solution 1a (Proposed Modification):

BSCCo calculate the marginal SBP and provide it to SAA. SAA runs without reporting to determine the BPA required to get the SBP. Manually amend the Buy Price Price Adjuster (BPA) and run Settlement to the timetable;

£22,890 change specific + operational: £25,296 p.a. and £20,051 per incident

Solution 1b (Proposed Modification):

BSCCo calculate the marginal SBP and the associated BPA and provide the BPA value to SAA. SAA manually amends BPA to match that provided by BSCCo and runs Settlement to the timetable;

£20,613 change specific + operational: £25,296 p.a. and £20,051 per incident

Software / System Solution:

Solution 1a (Proposed Modification):

SAA calculation change only;

£15,445 change specific + operational: £168 per incident

Solution 2a (Proposed Modification):

SAA calculation change, plus electronic flow, BMRA calculation and SAA reporting;

Not quoted for – due to time constraints

9.2 Transmission Company

Provided in full in Annex 5.

Proposed Modification:

No significant impact on systems or processes. An amendment to internal working procedures would be required to ensure reporting of the relevant systems warning messages to BMRA;

No direct costs identified, however, minor costs would be incurred by the requirement for additional training to give effect to the changes to internal working procedures.

9.3 ELEXON

Provided in full in Annex 3.

9.3.1 Market Monitoring and Reporting

Timescales exclude Integration testing, other testing (i.e. other than TOMAS and MDM testing) and BSC Auditor involvement.

Manual Solution: Proposed Modification

TOMAS Software – development **6 man days**, testing (including regression) **24 man days**, **excluding documentation changes**;

MDM (if new flow to be received) – development **5 man days**, testing (including regression) **15 man days**, **excluding documentation changes**

Operational impact: 2 man days per week.

System Solution: Proposed Modification

TOMAS Software – development **5 man days**, testing (including regression) **12 man days**, **excluding documentation changes**;

MDM (if new NGC flow to be received) – development **5 man days**, testing (including regression) **15 man days**, **excluding documentation changes**

9.3.2 Corporate Communications

Whether urgent Modification 135 or Alternative Modification 135 be implemented the impact on the BSC (ELEXON) website will be similar.

It would be necessary to modify the static content on the Pricing Data page explaining the changes to the derivation of the pricing calculation and resulting data, and amendments would be required to the content of each individual TOMAS web price report <SBP/SSP/NIV> published within the Pricing Data section.

In addition, provision would also be made for the publishing of the demand control period duration (in time and in settlement periods) within the Pricing Data section.

Allow **6 man days** to carry out the work described above, this figure is inclusive of development and testing.

9.3.3 ELEXON Assurance

Delivery Assurance and ELEXON Audit by Systems Assurance Team **– 20 man days**;

Obligations Register Amendment **– 0.5 man days**;

Amendment to ELEXON BPM – **1 man day;**

Service Delivery Documentation **– 5 man days.**

10 LEGAL TEXT TO GIVE EFFECT TO THE PROPOSED MODIFICATION

10.1 PSMG Consideration of the Legal Text

The PSMG considered the draft legal text at their meeting of 2 September 2003.

The majority of the PSMG agreed the form of the legal drafting, provided in section 10.2.

However, one member of the PSMG, noting the limited demand control circumstances that P135 applies to wished to include a detailed description of the circumstances under which the Transmission Company determines a Demand Control Period for the purposes of the Code, and suggested the following wording:

4.4.4C

For the purposes of paragraph 4.4.5 (a) and 4.4.5 (a1) only, where the Transmission Company instructs demand control in accordance with the provisions Grid Code OC6, and where such demand control is instructed in relation to any demand control method contained in paragraph OC6.1.2 (c) (d) or (e) of the Grid Code in times of energy shortage and under no other circumstances (which for the avoidance of doubt includes where there is insufficient generation to meet demand in real time or, where there is an actual imbalance between generation and demand or, that the Transmission Company has taken all available generation and demand reduction bids and/or offers available to the Transmission Company to take irrespective of the location or, that nothing has been constrained by the Transmission Company or, that nothing is held in reserve by the Transmission Company (except that level of generation that a Reasonable and Prudent Operator (as defined in the Grid Code) would hold for the purposes of managing system frequency or system voltage or system thermal requirements) or, that the Transmission Company has used its best endeavors to maximse generation and reduce demand (without invoking any demand control method contained in paragraph OC6.1.2 (c) (d) or (e) of the Grid Code) including but not limited to utilising any capacity available from any Contracts or Agreements or Memorandums of Understanding or the like available to the Transmission Company) the Transmission Company will determine a "Demand Control Period" commencing from the time the demand control instruction is issued, and ceasing on the completion of the demand control action, as notified, as soon as is reasonably practicable following the end of the Demand Control Period, by the Transmission Company to BSCCo [and in a form of a System Warning Message to the BMRS].

Additionally:

For the avoidance of doubt, where a "Demand Control Period" has been declared by the Transmission Company due to insufficient generation to meet demand in real time resulting from the omission or negligence or error of the Transmission Company then the Transmission Company shall pay to the Party(s) out of balance those costs imposed on the Party(s) by virtue of a "Demand Control Period" being declared and them being out of balance due to the omission or negligence or error of the Transmission Company].

However, the majority of the PSMG acknowledged that, although the proposed wording reflects the circumstances that P135 is seeking to address, it is inappropriate to include it in the Balancing and Settlement Code as it would fall under the governance of the Grid Code.

Therefore the majority of the PSMG believe the legal text for Proposed Modification P135 to address the defect identified in the Modification Proposal.

10.2 Legal Text to Give Effect to Proposed Modification P135

The redlining indicates the proposed amendments required to give effect to Proposed Modification P135.

SECTION T, V11.0

4.4. Determination of Energy Imbalance Prices (SBPj and SSPj)

4.4.1 In respect of each Settlement Period, the System Total Accepted Offer Volume will be determined as follows:

$$TQAO_j = \Sigma^i\Sigma^n QAO^n{}_{ij}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over all Bid-Offer Pair Numbers for the BM Unit.

4.4.2 In respect of each Settlement Period, the System Total Accepted Bid Volume will be determined as follows:

$$TQAB_j = \Sigma^i\Sigma^n QAB^n{}_{ij}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over all Bid-Offer Pair Numbers for the BM Unit.

4.4.2A In respect of each Settlement Period, some of the accepted Bids and accepted Offers may be defined as De Minimis Accepted Bids and De Minimis Accepted Offers respectively in accordance with the provisions in Annex T-1, and all such De Minimis Accepted Bids and De

Minimis Accepted Offers shall be disregarded for the purposes of the calculation of energy imbalance prices.

4.4.2B In respect of each Settlement Period, the System Total Un-Priced Accepted Offer Volume will be determined as follows:

$TQUAO_j = \Sigma^i\Sigma^n QAO^n{}_{ij} - \Sigma^i\Sigma^n QAPO^n{}_{ij}$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over all Bid-Offer Pair Numbers for the BM Unit.

4.4.2C In respect of each Settlement Period, the System Total Un-Priced Accepted Bid Volume will be determined as follows:

$TQUAB_j = \Sigma^i\Sigma^n QAB^n{}_{ij} - \Sigma^i\Sigma^n QAPB^n{}_{ij}$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over all Bid-Offer Pair Numbers for the BM Unit.

4.4.3 In respect of each Settlement Period, some of the accepted Bids and accepted Offers may be defined as Arbitrage Accepted Bids and Arbitrage Accepted Offers respectively in accordance with the provisions in Annex T-1, and all such Arbitrage Accepted Bids and Arbitrage Accepted Offers shall be disregarded for the purposes of the calculation of energy imbalance prices.

4.4.4 In respect of each Settlement Period:

(a) some or all of the accepted Bids and accepted Offers may be defined as NIV Tagged Bids and NIV Tagged Offers respectively in accordance with the provisions in Annex T-1;

(b) some or all of the Buy Price Volume Adjustment (Energy) (EBVA) and Sell Price Volume Adjustment (Energy) (ESVA) may be defined as NIV Tagged EBVA and NIV Tagged ESVA respectively in accordance with the provisions in Annex T-1;

(c) some or all of the Buy Price Volume Adjustment (System) (SBVA) and Sell Price Volume Adjustment (System) (SSVA) may be defined as NIV Tagged SBVA and NIV Tagged SSVA respectively in accordance with the provisions in Annex T-1;

(d) some or all of the System Total Un-priced Bid Volume and System Total Un-priced Offer Volume may be defined as NIV Tagged System Total Un-priced Bid Volume and NIV Tagged System Total Un-priced Offer Volume respectively in accordance with the provisions in Annex T-1.

4.4.4A In respect of each Settlement Period, the Net Imbalance Volume will be determined as follows:

$NIV_j = \{\Sigma^i\Sigma^n QAPO^n{}_{ij} + EBVA_j + SBVA_j + TQUAO_j\} - \{\Sigma^i\Sigma^n (-QAPB^n{}_{ij}) + (-ESVA_j) + (-SSVA_j) + (-TQUAB_j)\}$

where Σ^i is the sum over all BM Units and Σ^n is either the sum over all Accepted Offers that are not De Minimis Accepted Offers and not Arbitrage Accepted Offers, or the sum over all Accepted Bids that are not De Minimis Accepted Bids and not Arbitrage Accepted Bids, as the case may be.

4.4.4B Without prejudice to paragraph 1.5A.4(b) and 1.5A.6(b), if in respect of a Settlement Period j and a Market Index Data Provider s either:

(a) the Individual Liquidity Threshold exceeds the Market Index Volume (QXP_{sj}); or

(b) the Market Index Data Provider fails for whatever reason to submit the Market Index Data in time such that it can be taken into account in the relevant Settlement Run,

the Market Index Volume (QXP_{sj}) and the Market Index Price (PXP_{sj}) for that Market Index Data Provider shall be deemed to be zero.

4.4.4C For the purposes of paragraph 4.4.5(a) and 4.4.5(a1) only, where the Transmission Company instructs demand control in accordance with the provisions of the Grid Code OC6, and where such demand control is instructed in relation to any demand control method contained in paragraph OC6.1.2 (c), (d) or (e) of the Grid Code, and is not required for locational reasons, the Transmission Company will determine a "**Demand Control Period**", comprising complete Settlement Periods only, commencing from the start of the Settlement Period within which the demand control instruction is issued, and ceasing at the end of the Settlement Period in which the demand control action is completed.

4.4.4D The Transmission Company shall:

(a) as soon as is reasonably practicable following the issue of a demand control instruction in accordance with paragraph 4.4.4C, notify the BMRS, by way of a System Warning message, of the time the demand control instruction was issued; and

(b) as soon as reasonably practicable following the end of the Demand Control Period notify:

(i) BMRS, by way of a System Warning message, of the time the demand control action was completed; and

(ii) BSCCo of the duration, in Settlement Periods, of the Demand Control Period.

4.4.5 In respect of each Settlement Period:

(a) that does not fall, all or part as the case may be, within a Demand Control Period, and if the Net Imbalance Volume is not equal to zero, and is a positive number, and $\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}$ is not equal to zero, then the System Buy Price will be determined as follows:

$$SBP_j = \{\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * PO^n_{ij} * TLM_{ij}\} + UEBCA_j\} / \{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}\} + \{BPA_j\}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over those accepted Offers that are not De Minimis Accepted Offers and not Arbitrage Accepted Offers and not NIV Tagged Offers;

(a1) that falls, all or part as the case may be, within a Demand Control Period, and if the Net Imbalance Volume is not equal to zero, and is a positive number, and $\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}$ is not equal to zero, then the System Buy Price will be determined as the maximum of:

(i) the price (in £/MWh) of the most expensive Period Priced Accepted Offer, all or part as the case may be, that is not a NIV Tagged Offer; or

(ii) the price associated with the Untagged Energy Buy Price Volume Adjustment ($UEBVA_j$) (converted to a price in £/MWh by $EBCA_j$ / $EBVA_j$).

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over those accepted Offers that are not De Minimis Accepted Offers and not Arbitrage Accepted Offers and not NIV Tagged Offers;

(b) if the Net Imbalance Volume is equal to zero, or is a negative number, and / or $\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}$ is equal to zero, then the System Buy Price will (subject to paragraph 4.4.6A) be determined as follows:

$$SBP_j = \Sigma^s \{PXP_{sj} * QXP_{sj}\} / \Sigma^s \{QXP_{sj}\}$$

where Σ^s represents the sum over all Market Index Data Providers;

provided that, if the Net Imbalance Volume is a negative number and SSP_j as determined in accordance with paragraph 4.4.6(a) would exceed SBP_j as determined in this paragraph (b), then SBP_j shall instead be equal to SSP_j as determined in accordance with paragraph 4.4.6(a).

4.4.6 In respect of each Settlement Period:

(a) if the Net Imbalance Volume is not equal to zero, and is a negative number, and $\{\Sigma^i\Sigma^n \{QAPB^n_{ij} * TLM_{ij}\} + UESVA_j\}$ is not equal to zero, then the System Sell Price will be determined as follows:

$$SSP_j = \{\{\Sigma^i\Sigma^n \{QAPB^n_{ij} * PB^n_{ij} * TLM_{ij}\} + UESCA_j\} / \{\Sigma^i\Sigma^n \{QAPB^n_{ij} * TLM_{ij}\} + UESVA_j\}\} + \{SPA_j\}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over those accepted Bids that are not De Minimis Accepted Bids and not Arbitrage Accepted Bids and not NIV Tagged Bids;

(b) if the Net Imbalance Volume is equal to zero, or is a positive number, and / or $\{\Sigma^i\Sigma^n \{QAPB^n_{ij} * TLM_{ij}\} + UESVA_j\}$ is equal to zero, then the System Sell Price will (subject to paragraph 4.4.6A) be determined as follows:

$$SSP_j = \Sigma^s \{PXP_{sj} * QXP_{sj}\} / \Sigma^s \{QXP_{sj}\}$$

where Σ^s represents the sum over all Market Index Data Providers;

provided that, if the Net Imbalance Volume is a positive number and SSP_j as so determined would exceed SBP_j as determined in accordance with paragraph 4.4.5(a), or 4.4.5(a1) as the case may be, then SSP_j shall instead be equal to SBP_j as determined in accordance with paragraph 4.4.5(a) or 4.4.5(a1) as the case may be.

4.4.6A Without prejudice to paragraph 1.5A.4(b) and 1.5A.6(b), if for whatever reason (including the submission or deemed submission of zero values or the absence of Market Index Data) in respect of a Settlement Period:

$$\Sigma^s\ QXP_{sj} = 0$$

where Σ^s represents the sum over all Market Index Data Providers,

then (notwithstanding paragraphs 4.4.5(b) and 4.4.6(b)):

(a) if the Net Imbalance Volume is a positive number, and $\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}$ is not equal to zero, SSP_j shall be equal to SBP_j as determined in accordance with paragraph 4.4.5(a) or 4.4.5(a1) as the case may be;

(b) if the Net Imbalance Volume is a positive number, and $\{\Sigma^i\Sigma^n \{QAPO^n_{ij} * TLM_{ij}\} + UEBVA_j\}$ is equal to zero, each SBP_j and SSP_j shall be zero;

(c) if the Net Imbalance Volume is a negative number, and $\{\Sigma^i\Sigma^n \{QAPB^n_{ij} * TLM_{ij}\} + UESVA_j\}$ is not equal to zero, SBP_j shall be equal to SSP_j as determined in accordance with paragraph 4.4.6(a);

(d) if the Net Imbalance Volume is a negative number, and $\{\Sigma^i\Sigma^n \{QAPB^n_{ij} * TLM_{ij}\} + UESVA_j\}$ is equal to zero, each SBP_j and SSP_j shall be zero; and

(e) if the Net Imbalance Volume is zero, each of SBP_j and SSP_j shall be zero.

4.4.7 In respect of each Settlement Period, the Total Accepted Priced Offer Volume will be determined as follows:

$$TQPAO_j = \Sigma^i\Sigma^n QAPO^n{}_{ij}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over those accepted Offers that are not De Minimis Accepted Offers and not Arbitrage Accepted Offers and not NIV Tagged Offers.

4.4.8 In respect of each Settlement Period, the Total Accepted Priced Bid Volume will be determined as follows:

$$TQPAB_j = \Sigma^i\Sigma^n QAPB^n{}_{ij}$$

where Σ^i represents the sum over all BM Units and Σ^n represents the sum over those accepted Bids that are not De Minimis Accepted Bids and not Arbitrage Accepted Bids and not NIV Tagged Bids.

4.4.9 In respect of each Settlement Period, the Total Arbitrage Volume will be determined as follows:

$$TAQ_j = \Sigma^i(\Sigma^{n'} QAPB^{n'}{}_{ij} - \Sigma^{n*} QAPO^{n*}{}_{ij})/2$$

where Σ^i represents the sum over all BM Units and $\Sigma^{n'}$ represents the sum over those accepted Bids that are Arbitrage Accepted Bids and Σ^{n*} represents the sum over those accepted Offers that are Arbitrage Accepted Offers.

4.4.10 In respect of each Settlement Period, the Total NIV Tagged Volume will be determined as follows:

$$TCQ_j = \{\{(\Sigma^i \Sigma^{n'} QAPB^{n'}{}_{ij}) + TTQUAB_j + TESVA_j + TSSVA_j\} - \{(\Sigma^i \Sigma^{n*} QAPO^{n*}{}_{ij}) + TTQUAO_j + TEBVA_j + TSBVA_j\}\}/ 2$$

where Σ^i represents the sum over all BM Units and $\Sigma^{n'}$ represents the sum over those accepted Bids which are NIV Tagged Bids and Σ^{n*} represents the sum over those accepted Offers which are NIV Tagged Offers.

SECTION X, ANNEX X-2, V13.0

Table X–2

Terms and Expressions Applying Except in Relation to Section S

Defined Term	Acronym	Units	Definition/Explanatory Text
Demand Control Period			The period (comprising complete Settlement Periods) notified by the Transmission Company as the 'Demand Control Period' in accordance with Section T4.4.4C.

ANNEX 1 – AVAILABLE SUPPORTING INFORMATION AND DATA

Indicative Analysis of the Marginal Price (Proposer's Analysis)

Historical analysis of what the marginal Energy Imbalance Prices would have been had the Energy Imbalance Prices been marginal in the period April 2002 to June 2003, noting that this analysis is limited to historical data and is based on a simplified Energy Imbalance Price derivation. Therefore the resultant prices are intended to provide only an indication of the general differences between an average Energy Imbalance Price methodology and a marginal methodology.

This is provided as a spreadsheet attachment to this report, 'UMRP135 Annex 1a'

ANNEX 2 - REPRESENTATIONS

Provided in attached document 'UMRP135 Annex 2.pdf'

Confidential responses are provided under separate cover to the Authority, in the attached document 'UMRP135 Annex 2 CONF.pdf'

ANNEX 3 – ELEXON IMPACT ANALYSIS

Provided in attached document 'UMRP135 Annex 3.pdf'

ANNEX 4 – BSC CENTRAL SERVICE AGENT IMPACT ANALYSIS

Provided in attached document 'UMRP135_Annex 4.pdf'

ANNEX 5 – TRANSMISSION COMPANY ANALYSIS

Q	Question	Response
1	Please outline any impact of the Proposed Modification on the ability of the Transmission Company to discharge its obligations efficiently under the Transmission Licence and on its ability to operate an efficient, economical and co-ordinated transmission system.	We believe that the implementation of P135 will enable the Transmission Company to continue to discharge its obligations under the Transmission Licence.
2	Please outline the views and rationale of the Transmission Company as to whether the Proposed Modification would better facilitate achievement of the Applicable BSC Objectives.	We believe that the proposal better facilitates BSC applicable objective b) for the efficient, economic and co-ordinated operation of the Transmission System. We believe that the use of a marginal pricing methodology provides a clearer signal to the market of the costs associated with supplying energy to balance generation and demand; and therefore incentivises participants to contract forward and mitigate the risk of being out of balance at Gate Closure.

Q	Question	Response
3	Please outline the views and the rationale of the Transmission Company as to whether it is believed that there is an Alternative Modification that addresses the same defect as P135, and better facilitates the Applicable BSC Objectives that the Proposed Modification.	We do not believe that there is an Alternative modification that addresses the same defect as P135 that better facilitates the BSC Applicable Objective b).
4	Please outline the impact of the Proposed Modification on the computer systems and processes of the Transmission Company, including details of any changes to such systems and processes that would be required as a result of the implementation of the Proposed Modification	There would be no significant impact on our systems or processes as a result of the implementation of this modification. The proposed implementation option uses an existing process for the provision of information to the BMRA and inclusion on the System Warning screen. An update to our working procedures would be required to provide the relevant message information in the instance of demand control actions being taken.
5	Please provide an estimate of the development, capital and operating costs (broken down in reasonable detail) which the Transmission Company anticipates that it would incur in, and as a result of, implementing the Proposed Modification	No direct costs have been identified as a result of the changes required to implement this modification. However, there would be minor costs associated with additional training to give effect to the necessary changes to our working procedures.
6	Please provide details of any consequential changes to Core Industry Documents that would be required as a result of the implementation of the Proposed Modification	None identified.
7	Any other comments on the Proposed Modification	National Grid has responded separately to the P135 Urgent Consultation.

Q	Question	Response
1	Please outline any impact of the options proposed for an Alternative to P135 on the ability of the Transmission Company to discharge its obligations efficiently under the Transmission Licence and on its ability to operate an efficient, economical and co-ordinated transmission system.	The Alternative options to P135 will not adversely affect the ability of the Transmission Company to continue to discharge its obligations under the Transmission Licence.
2	Please outline the views and rationale of the Transmission Company as to whether the either or both options (a) and (b) proposed for an Alternative to P135 would better facilitate achievement of the Applicable BSC Objectives.	P135 seeks to better facilitate BSC Applicable Objective (b) by changing the way that energy imbalance prices are calculated. We do not believe that the issues outlined in option a) address the same defect as outlined in the original modification as it relates to the Offer payment mechanism rather than the energy imbalance price. Option b) which deals with the treatment of unsupplied and reduced demand volume (as a result of Demand Control) is not encompassed within the current baseline of the Code and again the original modification was not

Q	Question	Response
		raised to address this issue. On this basis we do not believe that either of the options a) or b) properly constitute an alternative to the original modification proposal and therefore do not support BSC applicable objective b) as evidenced in the original modification proposal.
3	Please outline the impact of the Proposed Modification on the computer systems and processes of the Transmission Company, including details of any changes to such systems and processes that would be required as a result of the implementation of either or both the options proposed for an Alternative to P135.	There would be no additional impact (over and above that for the original proposal) of the implementation of option a). We believe that option b) which incorporates a route for determining the volume reduced by Demand Control would be problematic and complex and would have significant implications for our internal systems and processes. Currently under the Grid Code LDSOs notify NGC of "an estimation of Demand reduction or restoration achieved." A process would be required to calculate accurately the volume of Demand Control and it is not clear to us, at this stage, how it will be done.
4	Please provide an estimate of the development, capital and operating costs (broken down in reasonable detail) which the Transmission Company anticipates that it would incur in, and as a result of, implementing the options proposed for an Alternative to P135.	The original intent for raising the modification P135, was to introduce a solution within a short timescale to address identified issues for the forthcoming winter. Bearing in mind these timescales we do not believe that any capital expenditure could be incurred on development work. Any changes would have to be implemented via a manual workaround with operating costs being incurred. We can not comment on the specific nature of these prospective costs until such time that a complete workaround solution has been developed. As indicated earlier we believe that arriving at a solution for determining volumes resulting from demand control would be a complex process. We believe that option a) would require significant changes to the SAA system to pay for all offers at the marginal price and we cannot envisage how this change could be achieved via a manual workaround. With respect to option b) we would need to develop a manual process for including the demand control volume in an Offer acceptance, assuming that a robust process can be developed for calculating this volume in the first place.
5	Please provide details of any consequential changes to Core Industry Documents that would be required as a result of the implementation of the options proposed for an Alternative to P135.	We believe that if objective b) was implemented there may be a requirement for a potential Grid Code change in order to facilitate the provision of additional information from the LDSOs to support a process for determining demand control volumes.

Q	Question	Response
6	Any other comments on the options proposed for an Alternative to P135.	National Grid has responded separately to the P135 Urgent Consultation.

ANNEX 6 – POTENTIAL ALTERNATIVE MODIFICATION TO P135

The PSMG discussed potential Alternative Modifications raised by the group and consultation responses, noting that any Alternative Modification is required to address the same defect as the Proposed Modification, and to better facilitate the Applicable BSC Objectives than the Proposed Modification.

It should be noted that the consultation in respect of P135 contained reference to only two of the proposed options for an Alternative – options (a) and (b) below. These were included, with the PSMG deliberations in respect of the options, in Annex 4 of the draft Urgent Modification Report provided for the consultation. This Annex 6 comprises the information provided for the consultation, and expands on it with the deliberations of the PSMG at their meeting of 2 September 2003.

The deliberations in respect of agreeing an Alternative are provided in section 1.3.2. However, the majority view of the PSMG was that there would be no Alternative Modification proposed for P135, because whilst, in the opinion of some of the PSMG, these potential alternatives reduced some of the adverse effects of P135, they did not solve the fundamental problems and not all were seen as addressing the stated defects of P135.

A minority of those PSMG members that do not support P135, believe that an Alternative should be proposed for P135, in order that a better option is provided to the Panel and the Authority for determination. However, each of these PSMG members had a different preferred Alternative, noting that none of those that proposed an Alternative believed it to be better than the current baseline, only better than P135, as follows:

1. One member supported the potential alternative of deeming the offer stack to be entirely comprised of energy balancing actions during periods of demand control, and calculating the SBP as an average of all acceptances in the stack, such that the average price is higher than the current mechanism, thus deriving a heightened price signal, but without the ‘teeth’ of a marginal price (option (c));

2. One member supported the potential alternative of, during periods of demand control, derive a marginal SBP, use the marginal SBP for paying Offer Acceptances during periods, include the volume deemed to have been delivered by demand control in the offer stack (for deriving the Net Imbalance Volume), with capping of the marginal price (options (a), (b) and (d), respectively);

3. One member supported the potential alternative of, during periods of demand control, derive a marginal SBP, include the volume deemed to have been delivered by demand control in the offer stack (for deriving the Net Imbalance Volume), with capping of the marginal price (options (b) and (d), respectively); and

4. One member supported the potential alternative of using an Administered price (option (e)) during periods of demand control, on the basis that the market can be deemed to have failed.

a Potential Options that may form an Alternative Modification

The PSMG considered a number of options that may have formed a potential alternative to P135. The potential alternative to Proposed Modification P135 seeks to extend the solution for P135, namely the application of a marginal System Buy Price where the Net Imbalance Volume (NIV) is positive (i.e. system is short), by additionally proposing that:

a) All Offer Acceptances in the Settlement Periods comprising a Demand Control Period are paid at the (marginal) System Buy Price;

b) The volume associated with demand control be included in the Offer stack for Net Imbalance Volume Tagging.

c) (c1) Amendment to the Energy Imbalance Price calculation such that the SBP is derived as a volume weighted average of all Accepted Offers that are not De Minimis Tagged and not Arbitrage Tagged. i.e. it is proposed that the Net Imbalance Volume (NIV) tagging process is not undertaken to calculate the SBP during times of demand control, as all actions undertaken by the Transmission Company would be deemed to be 'energy' related, i.e. insufficient generation to meet demand. The Continuous Acceptance Duration Limit (CADL) rule shall also be removed during times of demand control as even short duration acceptances shall be associated with 'energy' balancing;

   A variation (c2) on this which is the same, but where the Energy Imbalance Price calculation would be amended such that the SBP is derived from all Accepted Offers that are not De Minimis Tagged, not Arbitrage Tagged and not CADL Tagged.

d) A price cap on the Marginal Price, potentially along the lines of a cost similar to the Value of Lost Load; and

e) SBP derived from an Administered Price.

The PSMG considered options (c1), (c2), (d) and (e) at their meeting of 2 September 2003, (see section 1.3.2), and the following sections (b and c) refer only to previous PSMG deliberations in respect of options (a) and (b), (as consulted on).

b Addressing the Same Defect as Proposed Modification P135? (Options (a) and (b))

The proposer of the potential alternative noted that they believe this solution to address the same defect as P135 because P135 has been interpreted as addressing the defect of security of supply by using a marginal price to send price signals that incentivise forward contracting to ensure that generation meets demand.

The proposer believes that a marginal System Buy Price (calculated with the demand control volume in the Offer stack for Net Imbalance Volume Tagging) plus marginal Offer payments during the Demand Control Period addresses the same defect as P135, and thus can be considered to be an Alternative to P135.

A number of PSMG members do not believe that the potential alternative meets the defect of Proposed Modification P135, as P135 limits the scope of the Modification to the marginal System Buy Price only, retaining the 'paid as bid' aspect of the Balancing Mechanism and the current treatment of the volumes associated with demand control. Section 4.2 of the draft Urgent Modification Report explores the rationale for this choice in more detail, but effectively the limitation of scope is due to the urgency of the Modification and the requirement to implement a solution in time for this winter.

However, the majority of the PSMG agreed that the potential alternative does address the same defect and therefore should be assessed against the Proposed Modification to determine if it better facilitates the Applicable BSC Objectives than the Proposed Modification.

c Facilitating the Applicable BSC Objectives (Options (a) and (b))

In respect of whether the potential alternative is better at facilitating the Applicable BSC Objectives than P135, the proposer of the potential alternative believes that the proposed alternative is better than P135 because:

- The marginal price derived by P135 does not include the volume associated with demand control in the Energy Imbalance Price calculation, this may have the effect of weakening the marginal System Buy Price derived and, in extreme cases, making the system appear to have been long (discussed in more detail in section 5.1.2). Therefore including the volume associated with the demand control in the stack for NIV Tagging will derive a more "correct" (marginal) System Buy Price than P135, sending more accurate price signals;
- The 'paid as bid' aspect of P135 disincentivises Generators because (the following points are discussed in more detail in sections 5.1.2 and 5.1.3) generating close to capacity during Demand Control Periods places risk on a Generator in the event of trip during a this period, as a Generator will be exposed to a marginal System Buy Price for the full extent of the lost contracted volume, furthermore, the non Delivery of the Accepted Offer volume will incur the marginal System Buy Price for the non delivered volume. Thus the potential risk on a generator is perceived to be too high with limited ability to mitigate the risk.

The proposer of the potential alternative believes that this may cause Parties (that can) to withhold generation / plant for self balancing purposes, recognising that although this is in breach of the Grid Code, Parties may be incentivised to do so by the increased risk of exposure to high SBP, and those Parties that cannot self balance may choose not to generate at all, thus further degrading security of supply.

The proposer of the potential alternative believes that paying for accepted Offers at the marginal System Buy Price means that generators will be better able to manage the risk of trip at times of demand control, and will be incentivised to offer into the Balancing Mechanism, thus improving security of supply over the Proposed Modification P135.

The PSMG considered these views. A number of the PSMG did not agree that the potential alternative Modification is better than the Proposed Modification and provided the following rationale:

- The difficulty associated with determining the volume delivered by demand control means that the volume placed into the Offer stack for NIV Tagging will be inexact;
- Paying Offers at the marginal System Buy Price would incentivise generators to withhold generation from the forwards and spot markets, so that they could offer into the Balancing Mechanism and get the marginal price for all their generation; and
- Paying Offers at the marginal System Buy Price makes Offers neutral to non delivery, and this may create the potential for 'false' Offers. For example, a Supplier offers into the Balancing Mechanism in anticipation / on the off chance of an imbalance in the 'right' direction that looks as if the Offer

was delivered, thus being paid the marginal SBP for that accepted Offer volume, whilst not actually delivering the Offer.

However, the PSMG did not reach any conclusion as to whether the Alternative Modification better facilitated the Applicable BSC Objectives than Proposed Modification P135, but agreed that the potential alternative should be consulted on as part of the consultation on P135, in order to seek industry views on this potential alternative. The PSMG considerations in respect of these potential alternatives are provided in section 1.3.2.